ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322 **NOTICE OF FILING REJOINDER/REPLY TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT**

Tucson Electric Power Company ("TEP"), through undersigned counsel, submits its Rejoinder/Reply Testimony in Support of Settlement Agreement of David G. Hutchens, Susan M. Gray, Ann E. Bulkley, Ramondo J. Robey, Denise A. Smith, H. Edwin Overcast, Craig A. Jones, and Richard D. Bachmeier.

RESPECTFULLY SUBMITTED this 1st day of September, 2016.

TUCSON ELECTRIC POWER COMPANY

By [signature]
Bradley S. Carroll
Tucson Electric Power Company
88 East Broadway, MS HQE910
P.O. Box 711
Tucson, Arizona 85702

and

Michael W. Patten
Jason D. Gellman
Snell & Wilmer L.L.P.
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004

Attorneys for Tucson Electric Power Company

Original and 13 copies of the foregoing filed this 1st day of September, 2016, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing hand-delivered/mailed/e-mailed this 1st day of September, 2016, to:

Jane Rodda,
Administrative Law Judge
Hearing Division
Arizona Corporation Commission
400 West Congress
Tucson, Arizona 85701

Robin Mitchell
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Thomas Broderick, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Daniel W. Pozefsky, Chief Counsel
RUCO
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Barbara LaWall, Pima County Attorney
Charles Wesselhoft, Deputy County Attorney
Pima County Attorneys' Office
32 North Stone Ave., Suite 2100
Tucson, Arizona 85701
Charles.Wesselhoft@pcao.pima.gov
Consented To Service By Email

C. Webb Crockett
Patrick Black
Fennemore Craig, PC
2394 East Camelback Road, Suite 600
Phoenix, Arizona 85016
wcrockett@fclaw.com
pblack@fclaw.com
Consented To Service By Email

Kevin Higgins
Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, Utah 84111

Nicholas J. Enoch
Jarrett J. Haskovec
Emily A. Tornabene
Lubin & Enoch, PC
349 North Fourth Avenue
Phoenix, Arizona 85003

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, Arizona 85646
tubaclawyer@aol.com
Consented To Service By Email

Meghan H. Grabel
Osborn Maladon, PA
2929 North Central Avenue
Phoenix, Arizona 85012
mgrabel@omlaw.com
Consented To Service By Email

Gary Yaquinto, President & CEO
Arizona Investment Council
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004
gyaquinto@arizonaaic.org
Consented To Service By Email

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 E. McDowell Road, Suite 153
Phoenix, Arizona 85004
thogan@aclpi.org
Consented To Service By Email

Rick Gilliam
Director of Research and Analysis
The Vote Solar Initiative
1120 Pearl Street, Suite 200
Boulder, Colorado 80302
rick@votesolar.org
Consented To Service By Email

Briana Kobor, Program Director
Vote Solar
360 22nd Street, Suite 730
Oakland, CA 94612
briana@votesolar.org
Consented To Service By Email

Michael Alan Hiatt
Earthjustice
633 17th Street, Suite 1600
Denver, Colorado 80202
mhiatt@earthjustice.org
Consented To Service By Email

Craig A. Marks
Craig A. Marks, PLC
10645 N. Tatum Blvd., Suite 200-676
Phoenix, Arizona 85028
craig.marks@azbar.org
Consented To Service By Email

Pat Quinn
President and Managing Partner
Arizona Utility Ratepayer Alliance
5521 E. Cholla Street
Scottsdale, Arizona 85254

Kurt J. Boehm
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 1510
Cincinnati, OH 45202

The Kroger Co.
Attn: Corporate Energy Manager (G09)
1014 Vine Street
Cincinnati, OH 45202

Stephen J. Baron
J. Kennedy & Associates
570 Colonial Park Dr., Suite 305
Roswell, GA 30075

Travis Ritchie
Sierra Club Environmental Law Program
2101 Webster Street, Suite 1300
Oakland, California 94612
Travis.ritchie@sierraclub.org
Consented To Service By Email

Court S. Rich
Rose Law Group pc
7144 E. Stetson Dr., Suite 300
Scottsdale, AZ 85251
crich@roselawgroup.com
Consented To Service By Email

Jeffrey Shinder
Constantine Cannon LLP
335 Madison Avenue, 9th Floor
New York, NY 10017

Richard O. Levine
Constantine Cannon LLP
1001 Pennsylvania Ave, NW
Suite 1300 North
Washington, DC 20004

Thomas A. Loquvam
Pinnacle West Capital Corporation
P.O. Box 53999, MS 8695
Phoenix, AZ 85072
thomas.loquvam@pinnaclewest.com
Consented To Service By Email

Kerri A. Carnes
Arizona Public Service Company
P.O. Box 53072, MS 9712
Phoenix, AZ 85072-3999
Kerri.Carnes@aps.com
Consented To Service By Email

Tom Harris, Chairman
Arizona Solar Energy Industries Association
2122 W. Lone Cactus Dr., Suite 2
Phoenix, AZ 85027
Tom.harris@ariseia.org
Consented To Service By Email

Scott Wakefield
Hienton & Curry, PLLC
5045 N 12th Street, Suite 110
Phoenix, Arizona 85014-3302

Steve Chriss
Wal-Mart Stores, Inc.
2011 S.E. 10th Street
Bentonville, Arkansas 72716

Ken Wilson
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Samalayuca Dr.
Tucson, Arizona 85704-3224

Ellen Zuckerman
SWEEP Senior Associate
1627 Oak View Avenue
Kensington, CA 94707

Cynthia Zwick
Arizona Community Action Association
2700 North 3rd Street, Suite 3040
Phoenix, Arizona 85004

Kevin Hengehold
Arizona Community Action Association
2700 N 3rd St., Suite 3040
Phoenix, Arizona 85004

Bryan Lovitt
3301 West Cinnamon Drive
Tucson, Arizona 85741

Kevin M. Koch
P.O. Box 42103
Tucson, Arizona 85733

Karen White
139 Barnes Drive
Suite 1
Tyndall Air Force Base, Florida 32401
karen.white.13@us.af.mil
Consented To Service By Email

Kyle J. Smith
9275 Gunston Road (JALS RL/IP)
Suite 1300
Fort Belvoir, Virginia 22060
kyle.j.smith124.civ@mail.mil
Consented To Service By Email

Jeffrey W. Crockett
Crockett Law Group PLLC
2198 E. Camelback Road, Suite 305
Phoenix, Arizona 85016

Bruce Plenk
2958 N. St. Augustine Place
Tucson, Arizona 85712
solarlawyeraz@gmail.com
Consented To Service By Email

Garry D. Hays
Law Offices of Garry D. Hays, PC
2198 E. Camelback Road, Suite 305
Phoenix, Arizona 85016

Greg Patterson
Munger Chadwick
916 West Adams, Suite 3
Phoenix, Arizona 85007

Camila Alarcon
Gammage & Burnham, PLC
Two N. Central Ave., 15th Floor
Phoenix, Arizona 85004

Michele L. Van Quathem
Law Office of Michele Van Quathem, PLLC
7600 N. 15th St., Suite 150-30
Phoenix, Arizona 85020

David Bender
Earthjustice
1625 Massachusetts Ave., NW, Suite 702
Washington, D. C. 20036-2243

By Jaclyn Howard

REJOINDER TESTIMONY OF

DAVID G. HUTCHENS

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of David G. Hutchens

on Behalf of

Tucson Electric Power Company

September 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct, Rebuttal and Settlement Agreement Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Rejoinder Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. What is the purpose of your Testimony?

A. The purpose of my Testimony is to discuss the Company's current position on the residential basic service charge and volumetric tiers, to emphasize the importance of TEP's proposed changes to the lost fixed cost recovery mechanism ("LFCR") and to respond to Freeport Minerals Corporation ("Freeport") witness Michael D. McElrath.

II. TEP'S CURRENT POSITION ON THE RESIDENTIAL BASIC SERVICE CHARGE AND VOLUMETRIC TIERS.

Q. Is the Company updating its position regarding the residential basic service charge?

A. Yes. While TEP believes that the record supports its initial proposed residential basic service charge of $20 per month and Staff's initial proposal of $17 per month, the Company is updating its proposal to be consistent with (i) the Commission's recent decision in the UNS Electric rate case[1] and (ii) the recommendation set forth by Staff witness Solganick in Surrebuttal Testimony.[2] We now recommend that the Commission approve a basic service charge of $15 per month for standard two-part residential rates and a $12 monthly basic service charge for time-of-use ("TOU") and three-part rates. This additional compromise on the basic service charge is contingent upon having two volumetric rate tiers as proposed by the Company and Staff.

The record is clear that meaningful rate design changes are necessary in order to provide the Company with a better opportunity to recover its costs. An increase in the residential basic service charge coupled with the elimination of two volumetric energy tiers represent important steps toward this goal and is consistent with Staff's position.[3]

The Rejoinder Testimonies of Craig A. Jones, Richard D. Bachmeier, and Dr. H. Edwin Overcast provide additional initial information regarding the basic service charge.

---

[1] Decision No. 75697 (August 18, 2016), 66:7-19.

[2] Solganick Surrebuttal Testimony, 13:1.

[3] Solganick Surrebuttal Testimony, 13:2-3.

III. LOST FIXED COST RECOVERY MECHANISM.

Q. What is the purpose of the LFCR?

A. The LFCR, approved as part of a settlement agreement in TEP's last rate case, was intended to help the Company recover fixed cost-related revenue that is lost due to Commission Energy Efficiency ("EE") and Distributed Generation ("DG") policies. In its recent rate order for UNS Electric, the Commission acknowledged that:

> [w]hen fixed costs are partially recovered from the volumetric energy charge, and sales of energy decline, a utility may be unable to recover all of its fixed costs.[4]

The Commission further stated that:

> [t]he LFCR mechanism is not intended to operate as a full de-coupler mechanism, but rather to collect the lost fixed cost revenues associated with Commission-mandated programs such as Energy Efficiency and DG.[5]

Q. Does the current LFCR "collect the lost fixed cost revenues associated with Commission-mandated programs such as Energy Efficiency and DG?"[6]

A. No. Because TEP's current LFCR excludes recovery of lost revenue associated with a portion of distribution costs and all generation costs, the mechanism does not adequately address the impact of energy sales lost to DG and EE programs. That shortcoming can be

---

[4] Decision 75697, 122:14-15.
[5] Decision No. 75697, 126:9-11.
[6] Ibid.

remedied without resorting to a full decoupling mechanism. Instead, TEP is seeking to modify the LFCR design to better reflect its original purpose.

Q. Briefly summarize the Company's proposed changes to the LFCR.

A. TEP has proposed modifying the LFCR to more fully recover lost fixed cost revenues associated with Commission-mandated DG and EE programs to a cap of 2% of total retail revenues, up from the current 1% cap. These proposed changes also reflect the spirit of the Commission's 2010 policy statement on decoupling.[7]

Q. Why should more of TEP's lost fixed costs be included in the LFCR?

A. The current LFCR only recovers approximately 41% of the lost fixed costs associated with DG and EE.[8] While the impact of this shortcoming might once have been manageable, it is becoming increasingly untenable in the face of growing DG adoption rates in TEP's service territory and the gradual pace of rate design changes. Our fixed service costs undeniably include the retail jurisdictional amounts of distribution <u>and</u> generation assets. The record in this case is clear that TEP relies on volumetric energy sales to recovery the majority of its fixed costs. Therefore, the LFCR should be updated to include these costs.

Q. Do you agree with Staff witness Solganick that generation assets are "fungible?"[9]

A. No, not at all. Mr. Solganick states that generation is fungible because, "[E]nergy could be delivered to a new customer, an existing customer using slightly more energy, an economic development customer or sold off-system."[10] These speculative opportunities

---

[7] "Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency, as it establishes better certainty of utility recovery of authorized fixed costs and better aligns utility and customer interests." (Docket Nos. E-00000J-08-0314 and G-00000C-08-0314, December 29, 2010).
[8] See Rejoinder Testimony of Craig A. Jones.
[9] Solganick Surrebuttal, 26:11
[10] Solganick Surrebuttal, 26:12-13.

have not yet emerged and will not likely materialize going forward given the slow economic recovery in TEP's service territory, declining energy sales, reduced use per customer, and increasing DG installations. Even an unlikely return to TEP's historic growth levels would only partially mitigate the effects of regulatory lag. Because our rates are based on historic test years and overly reliant on volumetric charges, TEP will continue to struggle to recover its fixed costs and earn its authorized rate of return.

Q. Do you agree with Mr. Solganick that generation costs can be recovered through off-system sales?

A. No. Under our current rates, 100% of those short-term wholesale sales are already credited back to retail customers through the PPFAC. Moreover, as described in the Rejoinder Testimony of Ramondo J. Robey, the wholesale power market in the Southwest is currently very depressed, limiting TEP's ability to negotiate profitable long-term contracts.

Q. Are there other proposals that would further limit TEP's ability to recover its fixed costs?

A. Yes. The "buy-through" tariff would allow TEP's largest customers to "shop" for alternative energy resources, limiting the Company's ability to recover its generation costs between rate cases. These fixed costs would then need to be reflected in base rates in a future proceeding, placing the rest of our customers at risk for larger rate increases.

RUCO[11] and AECC[12] also propose a mechanism that would pass through to retail customers the margins on new long-term wholesale contracts that TEP enters into between rate cases. This change would remove one of the few tools that helps TEP partly

[11] Radigan Surrebuttal, 3:1-20
[12] Higgins Surrebuttal, 41:21-13.

offset the regulatory lag associated with new investments or declining sales, and provide long-term benefits to our retail customers by allocating portions of generation and transmission to wholesale customers. RUCO's and AECC's proposed mechanism also is unfairly asymmetrical, as it would not allow TEP to recover the costs associated with long-term wholesale contracts that expire between rate cases. Please refer to the Rejoinder Testimony of Ramondo J. Robey for additional information on this subject.

Q. Why are the Company's proposed LFCR changes so important?

A. Even if the Company's proposed rate design changes are approved in this case, TEP will remain heavily dependent on volumetric sales to recover its fixed costs. Moreover, assuming a January 1, 2017 effective date for new rates, the Company's sales will have already been impacted by an additional 18 months of EE programs and DG installations since the test year ending June 30, 2015. At TEP's current residential solar adoption rate, this means that more than 13,000 customers will lock in current rate designs and net metering benefits, preserving their ability to enjoy heavily subsidized electric service for decades to come. In light of such circumstances, an updated LFCR represents TEP's only realistic opportunity to recover its fixed service costs and earn a fair return on its investments without nearly constant, serial rate cases.

Q. Would TEP's proposed changes to the LFCR allow the Company to recover more revenue than is authorized in this case?

A. No. I would like to emphasize that even with TEP's proposed modifications, the LFCR would not allow the Company to recover revenues that are *incremental* to its authorized revenue requirement. The sole purpose of the LFCR is to provide TEP with recovery of revenues that it otherwise would have collected were it not for EE and DG.

Q. Would customers benefit from the Company's proposed LFCR changes?

A. Yes. The LFCR promotes gradualism by phasing in annually a portion of the lost fixed cost revenues attributable to EE and DG. Including lost fixed cost generation revenues would serve to mitigate the frequency and magnitude of future rate requests.

Q. Is there sufficient evidence in the record supporting TEP's proposed LFCR changes?

A. Yes. The Company's position is discussed and supported extensively in all three rounds of testimony filed in this docket.

IV. <u>RESPONSE TO FREEPORT MINERALS CORPORATION WITNESS MICHAEL D. MCELRATH.</u>

Q. Have you reviewed the Rejoinder Testimony of Freeport witness Michael D. McElrath?

A. Yes I have.

Q. Do you agree with Mr. McElrath's testimony that the Sierrita mine is TEP's largest customer and that the mine provides a tremendous economic benefit to Pima County and the state of Arizona?[13]

A. Yes, I do.

Q. Do you also agree that Freeport has been experiencing financial difficulties and it has considered closing down the Sierrita mine?

A. Yes. TEP closely monitors the business developments of many of its large commercial and industrial customers.

---

[13] McElrath Rejoinder Testimony, 4:25-26, 5: 1-15.

Q. Is it your understanding that energy prices contributed to Freeport's consideration of shutting down the Sierrita mine?

A. No. Based on my understanding of the situation, low commodity prices were the driving force behind the curtailment of operations at the mine. Freeport's third quarter 2015 SEC Form 10-Q stated that, "During October 2015, FCX [Freeport] initiated a plan to reduce operating rates at its Sierrita mine in Arizona in response to low copper and molybdenum prices. Initially, the plan involves operating the Sierrita mine at 50 percent of its current operating rate. FCX is also evaluating the economics of a full shutdown."

Q. Mr. McElrath states that the shutting down of the Sierrita mine, "...does not seem to concern TEP enough to make any meaningful buy-through proposal in this rate proceeding..."[14] Please comment on this statement.

A. Concern about our customers and a supporting a buy-through rate are not synonymous.. We are deeply concerned about the long-term economic viability of the Sierrita mine – our single largest customer and a huge employer in our community. While TEP is opposed to the proposed buy-through rates, TEP is continuing to analyze balanced options for the Sierrita mine.[15]

Q. If TEP could offer some relief to Freeport, would the Sierrita mine continue operating at current or increased levels?

A. I think Mr. McElrath is in a better position to answer this question than me, however the answer seems somewhat obvious. Freeport's 2nd quarter 2016 presentation to investors highlighted the company's most significant sensitivities to its earnings and cash flows.

---

[14] McElrath Rejoinder Testimony, 6:2-3.

[15] On July 14, 2016, Freeport filed a notice that it intends to be a party and file comments in the Commission's docket on Resource Planning and Procurement in 2015 and 2016 (Docket No. E-00000V-15-0094). Among other things, Freeport requests that the Commission require the consideration of, "[p]lanned long-term commitments to opt-out of a utility's native load generation obligations by qualified customers as a resource alternative in IRP planning."

All but one of the sensitivities listed related to changes in commodity prices. For example, a 10 cent movement in the price of copper would cause a $260 million change in Freeport's cash flows. While lower energy prices might provide some short-term relief to Sierrita, prices for copper, molybdenum and other commodities appear more likely to drive Freeport's operating decisions.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

REJOINDER TESTIMONY OF

SUSAN M. GRAY

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REJOINDER TESTIMONY OF

SUSAN M. GRAY

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

SEPTEMBER 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Susan Gray. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony and Rebuttal Testimony in this docket?

A. Yes.

Q. What is the purpose of your Rejoinder Testimony?

A. The purpose of my Rejoinder Testimony is to respond to some of the more significant statements made by IBEW's witness Northrup in his Surrebuttal Testimony. Mr. Northrup's Rebuttal Testimony provides examples of what he considers "marked deterioration in the reliability and safety of TEP's operations" and includes pictures of situations that Mr. Northrup believes are unsafe. We have examined each and every one of these alleged unsafe conditions and found his assertions to be false. Moreover, it is unconscionable that Mr. Northrup points to these as examples of unsafe conditions, yet did not show concern for the public and employees to bring these conditions to the attention of the Company with any specificity, at the time the alleged conditions were discovered. As previously stated, the Company has several joint safety programs, an annual assessment of its safety processes, and many well-established channels to report safety concerns to the Company to have those concerns immediately addressed.

Q. Do you have any general comments regarding the Company's commitment to safety and reliability?

A. Despite Mr. Northrup's mischaracterizations to the contrary, as I have stated in my Direct and Rebuttal, TEP has maintained an exemplary safety and reliability record and has demonstrated consistent improvement year after year. Mr. Northrup's completely unfounded claims that there has been "marked deterioration in the reliability and safety of TEP's operation" will be discussed in further detail in this Rejoinder Testimony.

II. RELIABILITY AND SAFETY.

Q. On page 1 lines 21-24 and page 2 lines 1-4 of Mr. Northrup's Surrebuttal Testimony, he states that there has been a "marked deterioration in the reliability and safety of TEP's operation." To justify his statement, he later refers to the 4kV distribution system as "antiquated and obsolete." Do you agree?

A. No. While the vast majority (over 85%) of our customers are on 13.8kV distribution systems, our 4kV distribution systems are reliable and meet all requirements to remain in service. In fact, 2015 reliability data demonstrates that the Company's 4kV and 13.8kV distribution systems are equally as reliable. The ratio of outages per customer on the 4kV system was 0.64% versus 0.63% on the 13.8kV system. While the 4kV systems are older, the Company has maintained the performance as demonstrated by the reliability statistics. The Company is converting from 4kV to 13.8kV in a strategic, controlled and cost effective manner to improve operational flexibility by increasing the number of 14kV ties. This will allow TEP to serve larger customers than the 4kV system can support and to reduce distribution system losses.

Q. Please respond to Mr. Northrup's accusation about transformers lacking fuses.

A. Mr. Northrup also incorrectly states that there is not a fuse on transformers in the 4kV system. In recent discussions that I personally had with Mr. Northrup, he showed me a picture of a transformer without a fuse, so I believe this is the same transformer he is referencing in his testimony. The transformer in Mr. Northrup's picture was a Completely Self Protected (CSP) transformer, which are attached directly to the line without an external cutout or fuse because they have <u>internally</u> mounted circuit breakers and fuselinks that provide the <u>same</u> fusing capability. Thus, an external fuse is unnecessary for this type of transformer. However, since 1975, the Company adopted a conventional type of transformer that does not have internal breakers or fuselinks, so external cutouts or fuses are installed in conjunction with the transformer. TEP's Distribution Technical Manual references the fusing size for 4kV banks on Section 7.6 – Overhead Equipment Protection and section 7.7 – Underground Equipment Protection also references the fusing size for protecting the underground equipment for the 13.8kV and 4kV system. It is the current TEP standard to install an external fuse with a transformer. Contrary to Mr. Northrup's assertions, the 4kV system is reliable and the transformers are in fact safely connected.

Q. On page 2 lines 5-9 of Mr. Northrup's Surrebuttal Testimony, he references an example of an old, rotted electrical pole that hasn't been "pulled". Please respond to his testimony.

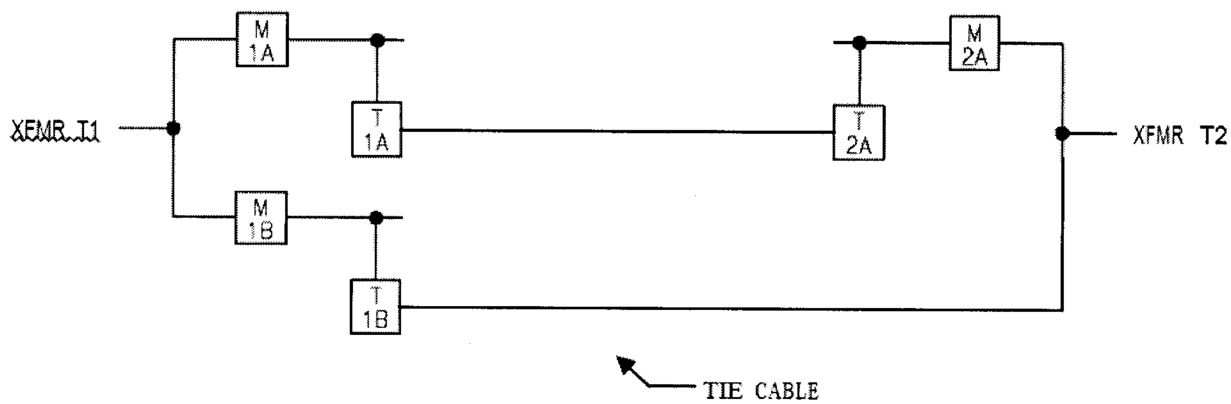
A. Third parties such as telecommunications companies commonly have joint use or joint attachment agreements with TEP, to use a portion of the pole for their equipment such as cable or fiber. A joint use agreement is an arrangement where both parties are owners of a percentage of the pole that is jointly used. A third party attachment agreement indicates that the third party company is not a pole owner and lease the communication section of the pole from TEP, per Federal Communication Commission rules. When TEP replaces a pole with either arrangement, TEP is required to notify parties and request that their equipment be transferred to the new pole. Each company is allowed 30 days to transfer their equipment and assignments are sequential, and not scheduled at the same time. After the final transfer notification has been received, TEP performs a post check and schedules the pole for removal. Exhibit A of Mr. Northrup's testimony does show a picture of a pole that needs to be removed. The manual process described above was not working very effectively, which is likely why this pole hasn't been removed. Again, I find it disappointing that Mr. Northrup prefers to use reports of such conditions through a rate case proceeding instead of notifying the Company immediately to be able to rectify the situation.

To address this notification issue, in 2015, TEP implemented the use of Notify™, a joint use process and asset management software. Notify™ has become the centralized area of sharing and communicating joint use activity by streamlining conversations between TEP and telecommunication companies. In addition to improving the transfer notification status, TEP is currently meeting regularly with telecommunication companies to strengthen relationships and improve communication efforts to address the backlog of pending transfers and pole removals.

Lastly, TEP is actively performing field checks for poles that are ready for removal without receiving completion of transfer notification. Field checks are performed routinely to identify poles that are ready for removal. TEP Telecommunication Specialists are also regularly field checking and submitting for pole removals. These practices are consistent with standard utility practice.

Q. On page 2 lines 16-19 of Mr. Northrup's Surrebuttal Testimony, he references Exhibit C and says that it is a picture of a 13.8kV feeder riser connected to a substation bus and claims that this is against industry standard. Do you agree with this claim?

A. No. The component in Exhibit C has been misidentified by Mr. Northrup as a feeder riser, but is actually a picture of tie cables at the Spanish Trail substation. It is TEP's standard to protect feeder risers with a 600A breaker, but tie cables in this configuration are protected by the transformer differential rather than a breaker. Mr. Northrup's assertion that this configuration is not industry standard and not properly protected is incorrect. The configuration at Spanish Trail is depicted in the figure below. Spanish Trail has two transformers, T1 and T2, which are configured to automatically throw over (or pick up the other transformer's load) when a transformer trips offline. Since T1 has two switchgears (1A and 1B) and T2 has one switchgear (2A), tie cables are necessary to tie switchgear 1B to transformer T2. This configuration is appropriate and meets all applicable utility industry standards.



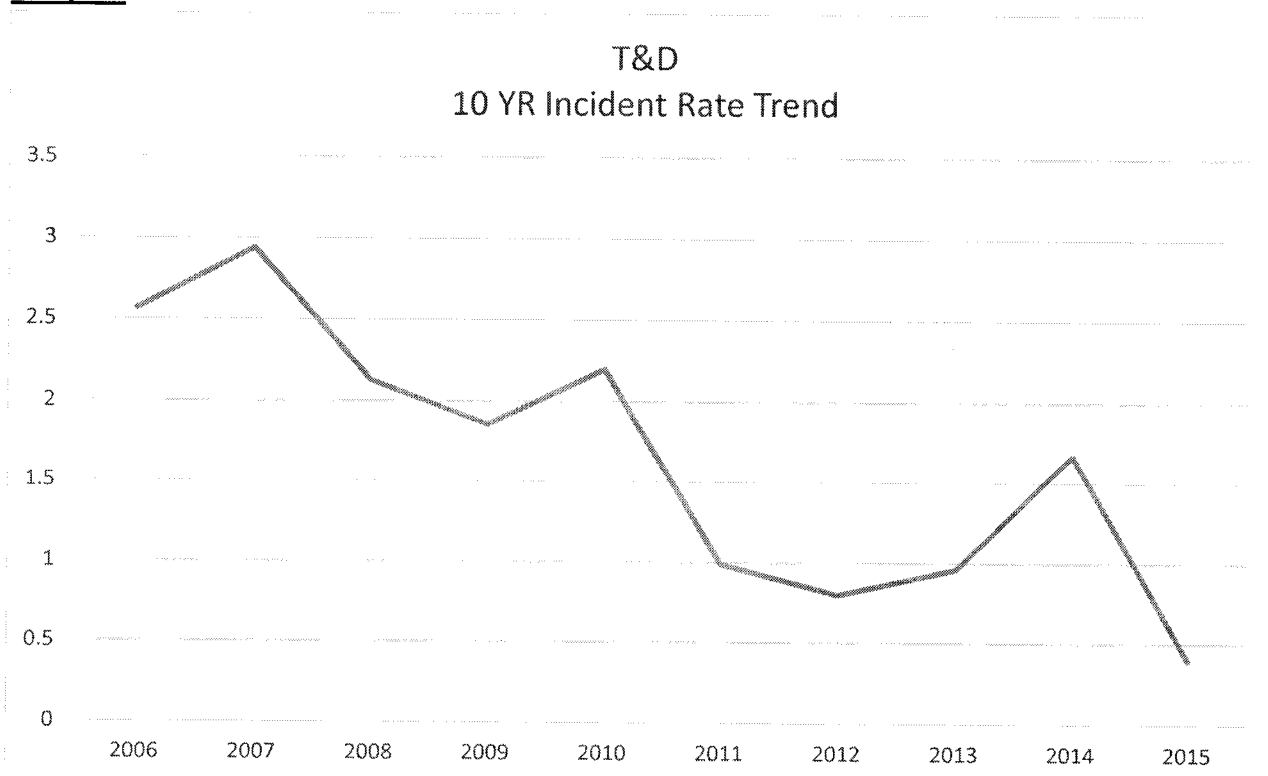
Q. On page 3 lines 6-10 of Mr. Northrup's Surrebuttal Testimony, he references the Hartt Substation in Green Valley as having a massive outage due to outdated and overloaded equipment. Please respond to this assertion.

A. If Mr. Northrup is referring to the outage that occurred on June 19, 2016, which affected one feeder at the Green Valley substation for only 10 minutes, then I disagree with his characterization of this as a "massive outage" and that it was due to "outdated equipment." The record-setting heat on that date led to an overloaded circuit and a need to transfer load from the Green Valley substation to the Hartt substation. Green Valley substation experienced over 2.5MVA of load growth in a single year; with the vast majority of load being in the Quail Creek area. In order to be able to have greater operational flexibility and to avoid future overloads, the 4.7MVA transformer at Hartt was replaced with a 12.5/15MVA transformer. Hartt substation also now has the capacity to accommodate anticipated load growth in the Green Valley area for 6 – 10 years.

Q. On page 3 lines 10-14 of Mr. Northrup's Surrebuttal Testimony, he compares the Total Recordable Incident Rate (TRIR) in 2012 to 2016 and states "This is nearly double the amount of injuries in half the amount of time." Please respond to his claim.

A. Safety is a top priority for TEP Leadership and any injury is a cause for concern. We continue to identify opportunities for improvement regarding safety and won't be satisfied until we meet our Target Zero goal of having no injuries. In my Rebuttal Testimony, I stated that the T&D TRIR has hovered around 1.0 from 2012 to June of 2016, which reflects on average one OSHA recordable incident per 100 workers per year. Safety performance has been consistently improving, as demonstrated in the 10 Year Incident Rate Trend chart below (Graph 1). The trend chart demonstrates that while there are year-to-year fluctuations, our recordable injury rate has trended downward and we continue to outperform the industry average.

__Graph 1__



Mr. Northrup's statement that the 2016 TRIR of 1.59 "is nearly double the amount of injuries in half the amount of time" is inaccurate. The 2016 TRIR of 1.59 reflects January through June 30th, so it is half the amount of time. In both 2012 and 2016 (through June), the TRIR reflects only 4 incidents for the timeframe, so it would be more accurate to say that the same number of incidents has occurred in half the time. A brief description of the injuries in both years is in the table below for comparison. In 2012, the four incidents occurred within the first eight months and ten days. This year's incidents have occurred in almost the same time period, so the rates are nearly identical.

Date of Incident	Brief Description of Incident
3/28/2012	Employee was driving on campus and was bitten/stung by insect. Insect bite.
5/14/2012	Employee lifted gate from 8032. Gate shifted upon lifting and heard pop in left shoulder. Shoulder strain.
7/24/2012	While reaching to the ground to get the drill check key, the ½ electric drill slipped off flat face of steel pole. It fell bit first through safety shoe, punctured left little toe. Foot laceration.
9/10/2012	Employee experienced pain in right wrist. Was transported to US Healthworks for examination. Employee was diagnosed with Carpal Tunnel. Carpal tunnel.
1/18/2016	An employee strained his wrist while operating a trailer jackstand. This is an OSHA recordable due to the rigid splint. Wrist strain.
3/29/2016	An employee wrenched their knee when they tripped over a cactus. Sprained knee.
5/12/2016	An employee strained his knee while holding a strand of wire on a fence for a co-worker. Sprained knee.

6/26/2016	An employee slipped and fell on a wet floor. Bruised back and shoulder.

Q. In his Surrebuttal Testimony on page 4, lines 3-7, Mr. Northrup references a request for substation breaker records. Do you agree with his testimony?

A. No. The union requested breaker records for a specific timeframe for the North Loop substation. The breakers were not serviced during that timeframe, so there were no maintenance records to report. However, the Union's assertion that the Company does not maintain records on breakers is just not accurate. TEP maintains records for all 1,349 of our substation breakers, whether they are designated as CIP or not. These records include the name plate information, test data, inspections and history of maintenance that has been performed on the breakers since the installation date.

Q. Please respond to Mr. Northrup's example of a safety incident in Kingman with a Sturgeon crew on page 4, lines 19-21.

A. TEP is not aware of the incident referred to in Mr. Northrup's testimony. Our standard practice when a contractor incident occurs is that the Company conducts an incident investigation to determine the root cause of the incident and identify mitigation actions that will prevent reoccurrence of safety incidents. We share the results of these investigations with our employees.

III. <u>WORKFORCE PLANNING.</u>

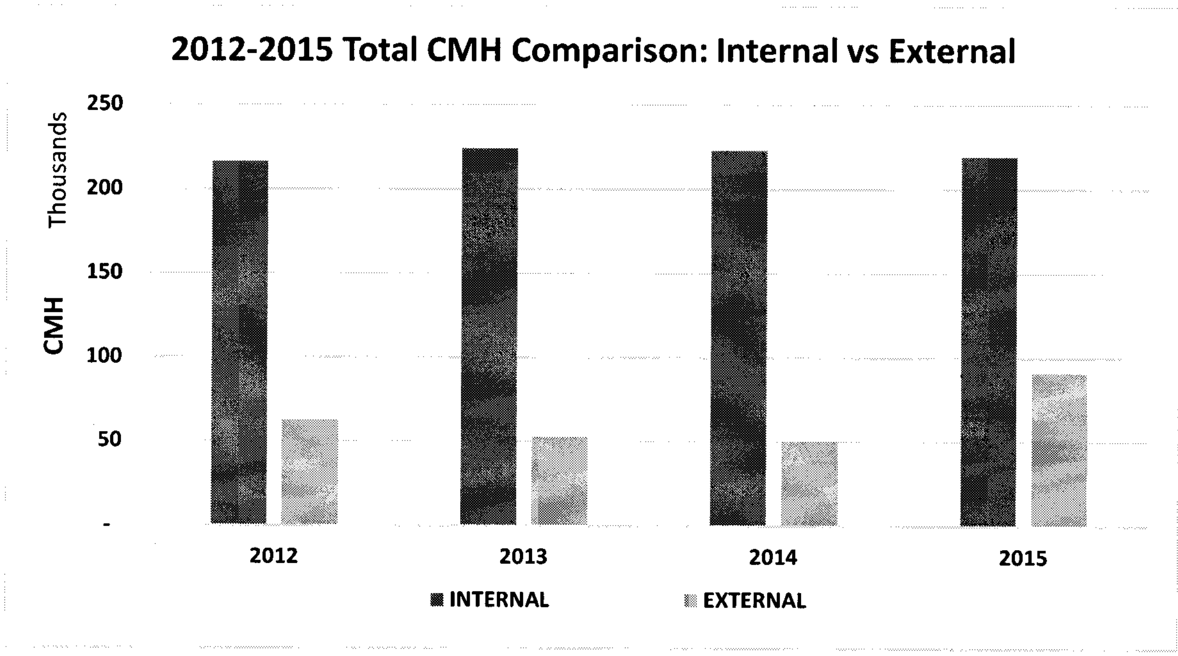
Q. Please respond to Mr. Northrup's testimony regarding TEP's workforce planning initiatives on page 5, lines 4-17 of his Surrebuttal Testimony.

A. After I filed my Rebuttal Testimony, we met with Mr. Northrup to explain our workforce planning approach. He has incorrectly interpreted the workforce planning process as limited to just a three year view. As I explained in my Rebuttal Testimony, the Company engages in a comprehensive business and workforce planning process annually – which looks out over a five year period of time. As outlined in our response to IBEW data request 1.07, we have an established development track for journeymen, with 8 steps of apprenticeship training prior to reaching journeyman status. Once journeymen status is reached, journeymen linemen work on a crew that has a crew leader who continues to provide guidance over the journeyman's work. While not part of an apprentice program, this requirement is outlined in the Crew Leader's job description. Both journeymen and crew leaders are responsible to train and guide the work of apprentices and pre-apprentices. This is also a requirement outlined in their job descriptions. Furthermore, this continuous progression ensures that 30-year plus employees do not depart from TEP 'without passing any knowledge along' as asserted by Mr. Northrup.

Q. On page 3 lines 19-22 of Mr. Northrup's Surrebuttal Testimony, he states that the crews do not have enough work to stay busy because TEP is assigning work to subcontractors. Do you agree with this statement?

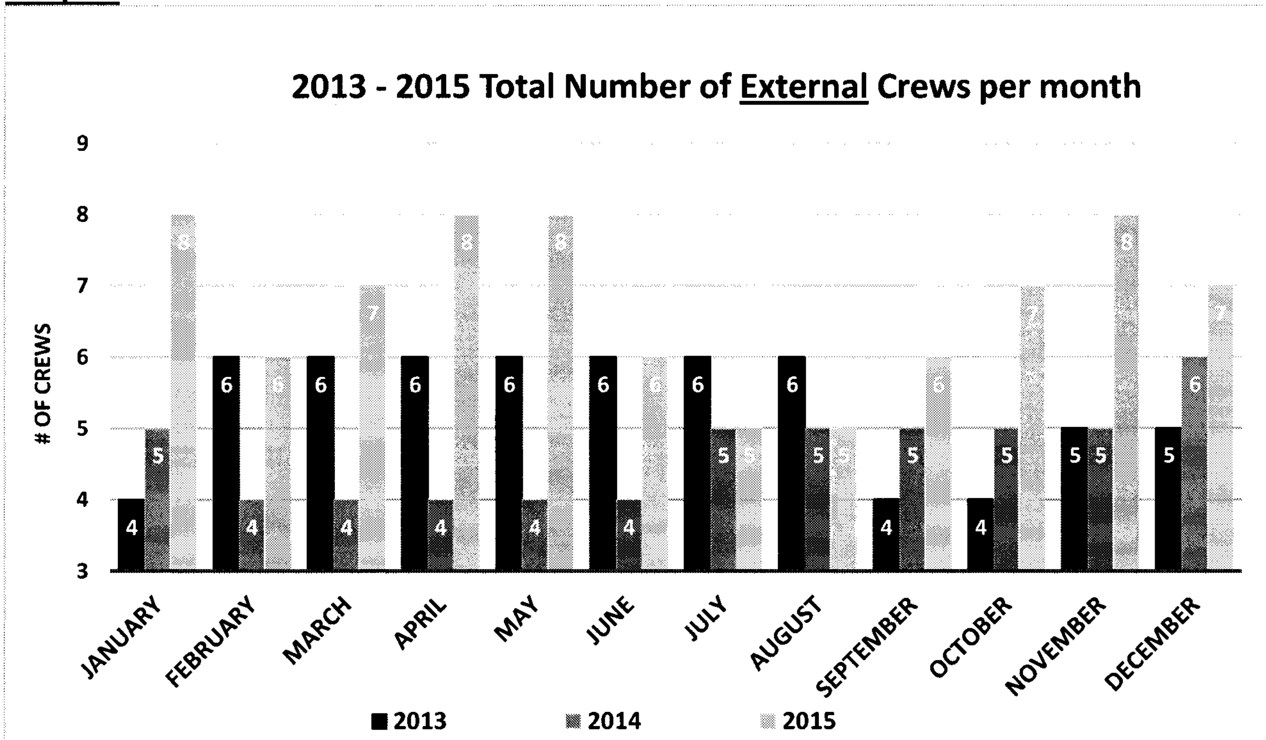
A. No. As stated in my Rebuttal Testimony, I am not aware of crews not having sufficient work to stay busy. When TEP's Resource Management Team is planning and prepping for Line Construction work, its first consideration is to account for the allocation of internal crew resources. Total work (Construction Man Hours ("CMH") completion) for internal crews has been steady for the past four years, see Graph 2 below.

Graph 2



Additionally, it should be noted that many factors impact the timing of line construction work including: customer deadlines, regulatory requirements, outage coordination and permits. Graph 3 illustrate the fluctuating use of external line construction resources used to accommodate the varying volumes of workload throughout the year.

Graph 3



Note: 2015 External crew count excludes the crews required to complete the Pinal Central-Tortolita 500kV Line.

The increase of external resources in the Fall of 2015 was due to the support needed to complete several 138kV line re-conductoring projects in order to comply with regulatory requirements. These large transmission projects were completed in December 2015. If we increased TEP resources to the level required to build these large projects, we would potentially have to lay off those employees when the project(s) are completed, which would be costly and inefficient.

Q. In his Surrebuttal Testimony on page 4, lines 11-15, Mr. Northrup asserts that the Distribution Design contractors "have no training on TEP's system, tools or standards" and that "they have produced no work." Please respond to this assertion.

A. I strongly disagree with Mr. Northrup's statements concerning training and work production. Both Distribution Design contractors came to TEP with 10+ years of experience in utility distribution design industry. They were provided over 450 hours of training which included advanced software training, observing and participating in the design process with senior design staff, additional instruction on safety standards and standard procedures specific to TEP. On the job training continues under the supervision of senior design personnel and they continue to work on projects of varying degrees of complexity, including capacitor removals and installations, Critical Circuit Patrol maintenance and subdivision layouts. In the 3 to 6 months that they have been contracted by TEP, they have completed designs for 27 work orders and have an additional 21 in progress. Contrary to Mr. Northrup's assertions, these contractors have been trained on TEP's system, tools and standards and they have produced a reasonable amount of work for the timeframe they have been with the Company.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

REJOINDER TESTIMONY OF
ANN E. BULKLEY

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIR
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of

Ann E. Bulkley

on Behalf of

Tucson Electric Power Company

September 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley, and I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. On whose behalf are you submitting this Rejoinder Testimony?

A. I am submitting this Rejoinder Testimony on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Did you previously submit testimony in this proceeding?

A. Yes. I submitted Direct and Rebuttal testimonies regarding the appropriate Return on Equity ("ROE"), capital structure, and Fair Value Rate of Return ("FVROR") for TEP in this proceeding.

Q. What is the purpose of your Rejoinder Testimony?

A. The purpose of my Rejoinder Testimony is to respond to the cost of capital issues raised by Mr. Michael P. Gorman on behalf of the U.S. Department of Defense and all other Federal Executive Agencies ("DOD") with respect to the Settlement Agreement filed with the Commission on August 15, 2016 ("Settlement Agreement").

Q. Have you prepared any exhibits to your Rejoinder Testimony?

A. Yes. I have included Exhibit AEB-Rejoinder-1 to this testimony, which has been prepared under my direction.

II. REJOINDER RESPONSE TO MR. GORMAN

Q. Please provide a brief overview of Mr. Gorman's Rebuttal Testimony and his recommendations.

A. Mr. Gorman opposes the Settlement Agreement filed with the Commission on August 15, 2016, and urges the Commission to reject it.[1] He states that the settlement is unreasonable and exceeds fair compensation for TEP's investment risk; and that the FVROR and OCRB increment exceeds a fair return on the value of TEP's rate base. Mr. Gorman, instead, recommends an ROE of 9.5 percent and a capital structure of 48.69 percent, which represents the company's test year capital structure before any adjustment for known and measurable changes. Mr. Gorman's ROE recommendation results in a FVROR of 5.10 percent. Mr. Gorman also levels several criticisms against my testimony and dismisses many of the issues raised in my testimony as being without merit, e.g. my challenges to his inclusion of proxy companies with negative growth rates in his DCF analyses and to his use of sustainable growth rates that create results that are substantially lower than the Value Line ROE forecasts that he bases his sustainable growth estimates on. We also have differing perspectives on the current market risk environment. Mr. Gorman also takes issue with my forward-looking market return and the resulting market risk premium; and to my calculation of the FVROR increment.

[1] The agreement was signed and authorized by the Residential Utility Consumer Office, Arizonans for Electric Choice and Competition, Freeport Minerals Corporation, Sierra Club, Western Resource Advocates, Noble Americas Energy Solutions, LLC, The Kroger Co., Wal-Mart Stores, Inc. and Sam's West, Inc., and the Arizona Investment Council.

Q. What has been agreed upon by parties to the Settlement Agreement.

A The Settlement provided for a 9.75 percent ROE and an embedded cost of long-term debt of 4.32 percent, resulting in a weighted average cost of capital of 7.04 percent. It also provided for a fair value rate of return of 5.34 percent.

Q. Please provide a brief overview of your response to Mr. Gorman with respect to his testimony and the appropriate ROE for TEP.

A There are many methodological and theoretical areas where Mr. Gorman and I significantly disagree. However, setting aside the methodological and theoretical differences, the ROE that is stipulated in the Settlement Agreement is 25 basis points above the ROE that Mr. Gorman suggests as a maximum return for TEP. While Mr. Gorman suggests that 9.50 is the maximum return the Commission should authorize for TEP, the range that he recommends in his rebuttal testimony as well as the litigated authorized returns in other regulatory jurisdictions that he relies on in his surrebuttal testimony support an ROE at the stipulated level of 9.75 percent. In addition, the Value Line projected ROEs for his proxy companies, which Mr. Gorman uses to develop the sustainable growth rate used in his DCF analysis supports an ROE that is consistent with my original recommendation of 10.35 percent. As shown in Mr. Gorman's Exhibit MPG-7, p. 1 of 2 to his direct testimony, the Value Line projected ROE estimates for the proxy group averaged 10.38 percent. Regarding the Company's capital structure, Mr. Gorman's recommendation to use the Company's test year capital structure of 48.69 percent ignores proforma adjustments allowed by this Commission for pending bond redemptions, to the test year actual capital structure. Finally, Mr. Gorman's criticisms of my estimated rate of return on the Fair Value increment are without merit, as each component of the calculation is based on investor expectations of market conditions.

Q. Mr. Gorman states that market evidence clearly shows that the market is embracing returns on equity of 9.5 percent and lower for electric utilities. Do you agree?

A No. There is no such "clear" evidence. Mr. Gorman himself states that investors should expect an ROE of 9.69, which is intended to reflect a measure of central tendency in the 2015 and 2016 authorized ROEs for vertically integrated electric utilities.[2] That return is closer to the stipulated ROE of 9.75 percent than his initial recommendation of 9.30 percent or his revised recommendation of 9.5 percent.

Q. How does Mr. Gorman derive the 9.69 percent expected return for vertically integrated utilities?

A. Reviewing the data Mr. Gorman relied on for this analysis, that return is calculated by taking the midpoint of the average litigated ROEs for both 2015 and 2016. I see no reason why it would be beneficial to rely on the midpoint of the average of these two periods rather than taking the midpoint or simple average over the entire time period. Furthermore, Mr. Gorman's 2016 average authorized ROE consists of only two data points. Mr. Gorman's data ranges from 9.3 percent to 10.35 percent for the period 2015-2016. If one were to take the midpoint of the high and low data points for that period, the result would be 9.8 percent. Calculating the simple average of each observation, the result is 9.73 percent. Regardless, any of these measures of central tendency (ranging from 9.69 percent to 9.8 percent) are supportive of a 9.75 percent ROE.

Q. Do you agree with Mr. Gorman that authorized ROEs are trending down in 2016?

A. No, I do not. As noted previously, there have only been two data points for litigated ROEs in 2016. As presented on Mr. Gorman's MPG-24, one case was above the

[2] Rebuttal Testimony of Michael P. Gorman, at 7, lines 17-18.

stipulated ROE (Indianapolis Power and Light at 9.85 percent) and one was below (El Paso Electric – New Mexico at 9.48 percent).[3] This data does not make a compelling case that utility ROEs are trending down.

Q. Do you agree with Mr. Gorman's conclusion that ROEs that were established in settlement should not be considered among evidence of recently authorized ROEs?

A. I recognize that settlements represent an agreed upon set of terms that all parties can accept. Therefore, it is possible that some elements may not be agreeable to all parties in the case. However, while that is the case, including settled ROEs in the 2015 to 2016 period has very little impact on the overall average. Mr. Gorman's evidence indicates that there is a 2 basis point difference between the average including settlements (9.70 percent) and the average excluding settlements (9.72 percent).

Q. What conclusion can be reached from review of Mr. Gorman's evidence on authorized returns for vertically integrated electric utilities?

A. Mr. Gorman's evidence supports TEP's stipulated ROE of 9.75 percent. Though the data shows that there have been instances of ROEs at or very close to 9.5 percent issued for vertically integrated utilities, the vast majority are in the upper 9 percent to the lower 10 percent range. In light of the additional perceived risk that TEP carries for its heavy reliance on coal-fired generation assets and its large capital expenditure program, I find an ROE upwards of 10 percent to continue to be reasonable. However, the Stipulated ROE of 9.75 percent as shown by Mr. Gorman's own evidence, is representative of an integrated electric utility of average risk and is a reasonable compromise for parties in the settlement.

---

[3] Surrebuttal Testimony of Michael P. Gorman, Exhibit MPG-24, p. 2 of 2.

Q. Has Mr. Gorman presented other evidence that supports an ROE of 9.75 percent?

A. Yes. In his rebuttal testimony, the high end of the range established by Mr. Gorman's analysis was 9.7 percent.

Q Mr. Gorman states on p. 10 of his Rebuttal that "authorized returns on equity have been declining but utilities' bond ratings have been improving…" Do you agree?

A. No. I do not agree with either portion of this statement. As I have discussed above, utility ROE determinations do not appear to be trending lower in 2016. Furthermore, Value Line is projecting ROEs for Mr. Gorman's proxy group to be significantly higher than the ROE that he recommends, demonstrating the expectation that authorized returns will trend higher in the near term. Furthermore, I find no recent evidence that bond ratings are improving for the electric utility segment.

Q. What is the basis of Mr. Gorman's statement that bond ratings have been improving?

A. Mr. Gorman based his comments on credit rating analysts' reports he cites in his direct testimony. Specifically, he cites a December 9, 2015, S&P report titled, "The Outlook For U.S. Regulated Utilities Remains Stable On Increasing Capital Spending And Robust Financial Performance." Interestingly, that report describes the ratings outlook for regulated utilities as "Stable with a slight bias toward the negative."[4] This is not exactly a ringing endorsement for an improving credit outlook. Similarly, Mr. Gorman cites a Fitch report from September 2015, that characterizes the industry outlook as "Stable"[5]; and a Moody's report from November 2015 that also characterizes the "outlook for the US regulated utilities industry [as] stable."[6] None of these reports indicate that bond

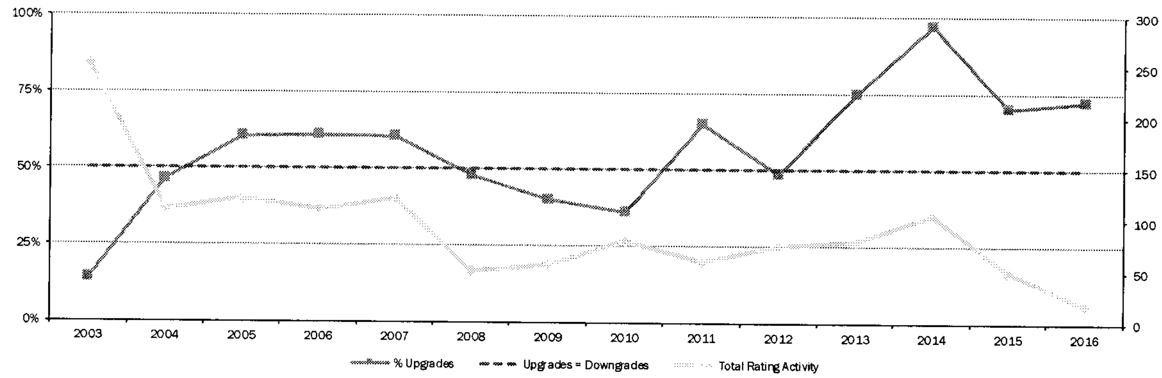
[4] Direct Testimony of Michael P. Gorman, at 5 line 12.
[5] *Ibid.*, at 6, line 25.
[6] *Ibid.*, at 6, line 32.

ratings are improving, but rather reveal that the outlook for regulated utilities is stable to slightly negative.

Q. Have you reviewed more recent studies regarding bond ratings?

A. Yes. EEI recently prepared a report that summarizes electric utility bond ratings and rating changes for 2016 to date. That study indicates that the ratio of positive to negative ratings actions have remained generally consistent with 2015 yields after having declined rather substantially over the past several years. Chart 1 below summarizes the data shown in EEI's Q1 2016 Update – Electric Utility Industry Financial Data and Trend Analysis, which I have also attached as Exhibit AEB-Rejoinder-1. The chart shows the number of ratings actions in each year (the lavender line and right vertical axis) and the ratio of upgrades to downgrades (the grey line and the left vertical axis). Based on the data shown in Chart 1, there has been no appreciable improvement in electric utility credit ratings.

Chart 1: Direction of Ratings Actions – U.S. Shareholder -Owned Electric Utility Industry



Source: EEI 2016 Q1 Credit Ratings Update, IV. Direction of Rating Action, derived from Fitch Ratings, Moody's, and Standard & Poor's.

Q. Has Mr. Gorman effectively presupposed the return on equity as projected by Value Line to be 10.38 percent for his proxy group in his calculation of the sustainable growth rate?

A. Yes, he has. The calculation of sustainable growth rates is in part premised on Value Line 3-5 year projections of ROE. As Mr. Gorman presents in his direct testimony at MPG-7, Value Line has estimated an ROE for each member of his proxy group that averages 10.38 percent for the group. He has made no attempt to reconcile this with the fact that when he uses the same data to reverse-engineer sustainable growth rates for his proxy group companies, the resulting ROEs for the same proxy group averaged 8.06 (mean) and 7.76 (median), more than 200 basis points lower. Mr. Gorman has not provided any reasonable explanation for such a large difference in ROE. Since he essentially abandons his sustainable growth ROE results, it is evident that Mr. Gorman even finds his sustainable growth results to be too low. In my opinion, the Value Line estimates of ROE for his proxy group provide another meaningful data point for this Commission to consider in its decision to set a just and reasonable ROE for TEP.

Q. Please summarize your response to DOD witness with respect to his capital structure recommendations for TEP.

A. Mr. Gorman recommends that the Commission adopt TEP's test year capital structure without allowing for adjustments for pending bond redemptions at the time of the test year end, but that have actually occurred. The test year capital structure Mr. Gorman recommends is already over a year old. This Commission has regularly considered adjustments for known and measurable changes to the test year capital structure. These adjustments are not allowed for items that "may" or "may not" occur, as Mr. Gorman states in his testimony, but in fact have occurred or will definitely occur and are measurable. It is appropriate for this Commission to approve TEP's proposed capital structure, adjusted for these known and measurable changes, of 50.03 percent equity and to reject Mr. Gorman's attempt to deny recovery for the higher amount of equity TEP already carries in its capital structure. I have shown in my analysis that TEP's proposed capital structure is reasonable in relation to the proxy group companies and should be accepted. The analysis provided by Mr. Gorman at Exhibit MPG-3 also shows that TEP's proposed capital structure is reasonable and within the range of proxy group company capital structures.

Q. Mr. Gorman states that a major flaw in your FVROR methodology is that you are not relying on observable market evidence to measure a fair rate of return on a fair value rate base, and that rather you are using a projected interest rate to capture a higher FVROR. Please explain your reasoning for using the projected interest rate.

A. I have estimated the nominal risk free rate for the FVROR calculation by taking the average of the forecast yield for the U.S. 30-year Treasury for two time periods, 2017-2021 and 2022-2026. I have relied on these long term averages as they incorporate investors expectation of movement in government interest rates. To use only today's anomalous and artificially low interest rate environment would result in an understatement of TEP's FVROR over the time period that these rates will be in effect. As discussed in my direct and rebuttal testimonies, due to the anomalous market conditions that have resulted in abnormally low yields on Treasury bonds, and the prospects that those conditions will change in the near term, it is appropriate to rely on forward looking estimates of interest rates in setting the return on the FV increment.

Q. Are there other ideological or methodological differences with Mr. Gorman that you have not addressed either in this testimony or in your Rebuttal Testimony?

A. The majority of the differences between Mr. Gorman's analysis and the analysis presented in my direct testimony have been discussed in my direct and rebuttal testimonies. However, Mr. Gorman provides a few additional criticisms of my analysis in his Surrebuttal testimony that I will address. Specifically, the exclusion of low outlier data from the DCF results, and the market risk premium calculation used in my CAPM.

Q. Mr. Gorman devotes a considerable portion of his Surrebuttal Testimony discussing your proposal to remove the results of Entergy and First Energy from his DCF results. He claims that to do so would "not produce an unbiased legitimate estimate of the current market cost of equity based on a DCF model." Do you concur?

A. No. Mr. Gorman suggests that it is inappropriate to exclude Entergy and First Energy from my proxy group and that he appropriately included them. I excluded these companies because they did not satisfy my screening criteria, i.e. did not have positive long-term earnings growth forecasts from at least two equity analysts. Both companies had negative growth rates by Zacks and Yahoo, and very low SNL growth rates. However, Mr. Gorman has included them in his proxy group, and the DCF results for these companies were 5.01 percent and 4.58 percent, respectively. Mr. Gorman suggests that removing two unreasonably low DCF results requires that you remove the same number of DCF results at the upper end of the range. I disagree. There were no extreme outliers that defied economic logic at the upper end of Mr. Gorman's data. In SoCal Edison, Opinion No. 445, the FERC acknowledged that "… investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return…"[7] In that same 2010 SoCal Edison proceeding the FERC found it to be "reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more, taking into account the extent to which the excluded low-end ROEs are outliers from the low-end ROEs of other proxy group companies. This gives the Commission flexibility to exclude proxy company results when the low-end ROE is somewhat above the average bond yield, but is still sufficiently low that an investor would consider the stock to yield essentially the same return as debt." This practice was affirmed in FERC Opinion Nos. 531[8] and 531-B.[9] With long term utility bonds very near to 4 percent, I believe it continues to be reasonable to remove Entergy and First Energy as low outliers from Mr. Gorman's DCF results.

Q. How do you respond to Mr. Gorman's criticism that your CAPM analysis is based on a forward-looking return on the market that is simply unjustified?

A. Mr. Gorman asserts that the estimated forward-looking market return used in my CAPM is based on a growth rate that cannot be sustained indefinitely. He claims the effect of this is to overstate the market DCF and correspondingly to overstate my calculation of the market risk premium. What Mr. Gorman is missing is that the market, as measured by the S&P 500 Index, is comprised of the largest companies on the New York Stock Exchange which are continually replaced when companies no longer fit the criteria for inclusion in the Index. So the concept of whether the companies in the Index "will

[7] FERC Opinion No. 445, 92 FERC ¶61,070, SoCal Edison Opinion (July 26, 2000) at 21.
[8] FERC Opinion No. 531, 147 FERC ¶61,234, NETOs Order on Initial Decision (June 19, 2014), para. 122.
[9] FERC Opinion No. 531-B, 150 FERC ¶61,165, NETOs Order on Rehearing (March 3, 2015), para. 60.

sustain their respective growth rates indefinitely" is misplaced since this occurs by replacing low performing companies with higher performing companies. In developing the S&P forward-looking market return, we are assuming that current growth rates will be sustained or will be substituted with others that are equally robust. Accordingly, my calculation of the forward market return and forward-looking market risk premium are appropriate. As indicated in my rebuttal testimony, the use of a constant growth DCF analysis for the S&P 500 companies to estimate the market return has been embraced by the FERC.[10]

III. CONCLUSIONS

Q. Please summarize your conclusions regarding the appropriate ROE for TEP.

A. I believe that the proposed settlement ROE of 9.75 percent is conservative based on the results of my ROE estimation methodologies, recently authorized ROEs for other vertically integrated electric utilities, the risk factors identified for TEP, and investors' expectation of market conditions over the period that rates will be in effect. However, it does provide a reasonable compromise to settle the matters in this case. Further, the Commission should uphold its policy of allowing certain known and measurable changes to TEP's test year capital structure and reject Mr. Gorman's attempt to deprive the company recovery for its higher equity costs.

Q. What is your recommendation for the FVROR for TEP?

A. Based on a 9.75 percent ROE, and a 1.00 percent return on the Fair Value Increment of rate base, I believe that a FVROR of 5.34 percent is within the range of reasonable returns for TEP.

---

[10] Rebuttal Testimony of Ann E. Bulkley, at 39 and 65.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

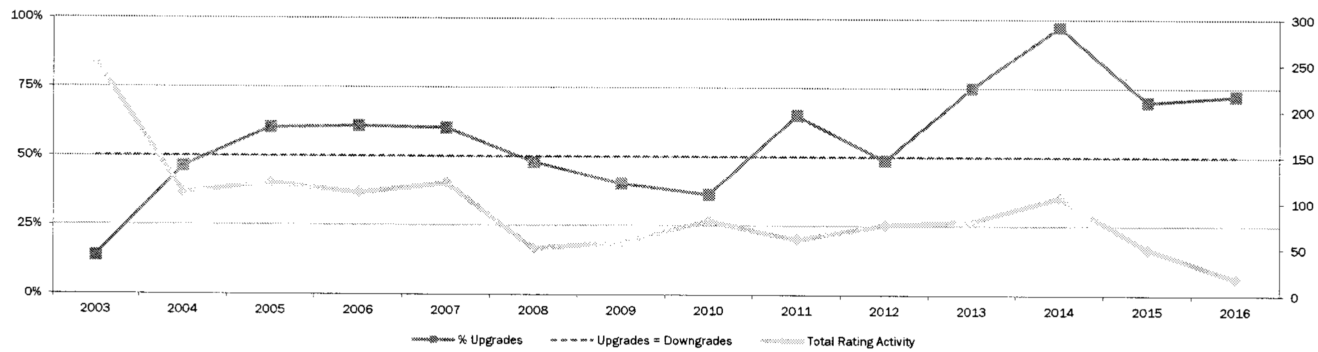
Exhibit AEB-Rejoinder-1

IV. Direction of Ratings Actions

Direction of Ratings Actions

U.S. Shareholder-Owned Electric Utility Industry

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Upgrades	21	35	51	73	67	73	24	23	29	39	37	60	103	35	13
Downgrades	279	218	59	48	43	48	26	34	51	21	39	20	3	15	5
% Upgrades	7.0%	13.8%	46.4%	60.3%	60.9%	60.3%	48.0%	40.4%	36.3%	65.0%	48.7%	75.0%	97.2%	70.0%	72.2%
Total Rating Activity	**300**	**253**	**110**	**121**	**110**	**121**	**50**	**57**	**80**	**60**	**76**	**80**	**106**	**50**	**18**
Upgrades = Downgrades	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%



Source: Fitch Ratings, Moody's, Standard & Poor's

REJOINDER TESTIMONY OF

RAMONDO J. ROBEY

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REJOINDER TESTIMONY OF

RAMONDO J. ROBEY

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

SEPTMBER 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Ramondo J. Robey and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes.

Q. Which Commission Staff or Intervenor Testimony do you address in your Rejoinder Testimony?

A. My Rejoinder Testimony addresses the testimony filed on behalf of Freeport Minerals Corporation and Arizonans for Electric Choice and Competition (collectively referred to as "AECC"), Noble Americas Energy Solutions, LLC. ("Noble Solutions"), and the Residential Utility Consumer Office ("RUCO") in the following subject areas:

- PPFAC Risk-Sharing Mechanisms
  - AECC and Noble Solutions Witness Kevin C. Higgins
- Margins from Long-Term Sales Contracts
  - AECC and Noble Solutions Witness Kevin C. Higgins
  - RUCO Witness Frank W. Radigan

II. PPFAC RISK-SHARING MECHANISMS.

Q. Has any witness recommended that a risk-sharing mechanism be incorporated in the Company's PPFAC?

A. Yes. AECC Witness Kevin C. Higgins maintained his recommendation for a 70/30 risk-sharing mechanism in the PPFAC in his Surrebuttal Testimony.[1]

Q. Do you agree with these recommendations?

A. No. Mr. Higgins' rationale for the sharing mechanism remains unsubstantiated and the Company does not agree with these recommendations for the reasons below.

Q. What quantitative support is there for implementing a 70/30 risk-sharing mechanism?

A. None. Mr. Higgins relies solely upon analogous and theoretical statements in order to make his recommendation. Initially, Mr. Higgins states that the "other western states of Wyoming, Oregon, Washington, Idaho, and Montana"[2] have sharing mechanisms. Mr. Higgins presents no quantitative analysis detailing the benefits, if any, of the risk-sharing mechanisms compared to TEP's current PPFAC. Also, Mr. Higgins ignores the significant resource and load differences between the utilities he references and the impact of their affiliates.

Mr. Higgins also states that a risk-sharing mechanism "provides a utility with the proper incentives to produce the greatest possible net benefit to its customers".[3] Once again, Mr.

---

[1] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 41, line 12.
[2] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 41, lines 12 - 13.
[3] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 41, lines 16 - 17.

Higgins fails to provide any supporting evidence for this claim. Most importantly, Mr. Higgins' entire premise for a risk-sharing mechanism is based upon his own assumption that TEP's management of its fuel and purchase power costs are not aligned with its customers' interests. The repeated proposals for a risk-sharing mechanism are only supported by the mere observation that other utilities have risk-sharing mechanisms and the apocryphal claims of *possible* improvements to TEP's PPFAC. The management of purchased power and fuel resources requires rigorous analysis and a change in the treatment of such costs should require analysis as well.

Q. What differences are there between TEP and the utilities in Wyoming, Oregon, Washington, Idaho, and Montana which Mr. Higgins references[4]?

A. The primary differences between TEP and the utilities referenced by Mr. Higgins are (i) the corporate structure and (ii) the generation resources available to the utilities. Rocky Mountain Power ("RMP") spans 3 states, with customers in Idaho, Utah, and Wyoming. Most importantly, RMP is a part of PacifiCorp, a large integrated utility with 1.8 million customers (over four times the customer count of TEP), 10,900 megawatts ("MW") of generation capacity, and 72 generation plants.[5] Mr. Higgins mentions the risk-sharing mechanisms in several western states but fails to mention that the risk-sharing determination in these states is predominately facilitated by a single expansive utility with a unifying generation component present; hydroelectric generation.

RMP and PacifiCorp own 41 hydroelectric plants[6] with a combined generation capacity of 1,135 MW. The presence of such a significant amount of hydroelectric generation at RMP and PacifiCorp "allows for a flexible means of generation dispatch. Generating

---

[4] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 41, lines 12 – 13.
[5] http://www.pacificorp.com/about/co/cqf.html
[6] Ibid

plants powered by coal or natural gas cannot accommodate rapid changes in demand as swiftly as hydropower. Hydropower also is a resource that works in concert with other renewable resources, such as wind power."[7] The flexibility of hydroelectric generation is augmented by the fact that MWs can be stored in form of water. TEP does not own nor operate a single MW of hydroelectric generation. RMP and PacifiCorp are able to utilize 1,135 MW of their resources in a manner akin to binary options. TEP has no such luxury, and all volatility from renewable resources and load is served through the dispatch of coal and natural gas resources. This difference is important when comparing TEP to RMP and PacifiCorp. Once again, a quantitative analysis of the TEP PPFAC and generation resources would quickly reveal this difference.

Q. What is your response to Mr. Higgins' assertion[8] that the Wyoming sharing mechanism is not based upon a comparison to forecasts?

A. Mr. Higgins' claim that the sharing mechanism in Wyoming is based upon net purchased power in rates[9] and not on a forecast is inaccurate. The net purchased power cost in Wyoming's rates is based upon a forward looking forecast derived by the utility. As referenced in the 2015 Direct Testimony of Belinda J. Kolb, Ph.D. regarding RMP and PacifiCorp in Wyoming states that:

> In its rate case application, the Company filed a <u>forecast</u> Base Net Power Cost of approximately $1.556 billion, Total Company, of which approximately $269 million is allocated to Wyoming. The Net Power Cost

[7] http://www.pacificorp.com/es/hydro.html

[8] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 43, lines 14 – 22.

[9] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 43, lines 19 – 20.

> total is derived from the Generation and Regulation Initiative Decision Tool (GRID).[10]

The forward test year used in the company's 2015 application was from January 1 to December 31, 2016. In addition, this same testimony also describes how the GRID tool is used to forecast net power costs rates for all of PacifiCorp's jurisdictions:

> GRID is an hourly production cost dispatch model that dispatches PacifiCorp resources to serve customer load in the most economic manner under a set of system constraints. GRID is primarily used to derive normalized Net Power Costs for rate cases and avoided cost prices to be paid to Qualifying Facilities. GRID has been used in every general rate case since 2002 in all of PacifiCorp's jurisdictions and as such is considered to be vetted and an appropriate modeling tool to forecast Net Power Costs.[11]

Mr. Higgins' own Surrebuttal Testimony also supports my observation that benchmarking a sharing mechanism to the Company's approved power rate is a circular test of its forecast. Note Mr. Higgins' quote from the Wyoming Public Service Commission:

> However, we find, based on the testimony from the other parties that the sharing band has and will continue to incent RMP to improve its forecasts of base [net power costs] costs...[12]

---

[10] Pre-filed Direct Testimony of Belinda J. Kolb, Ph.D. before the Public Commission of Wyoming. (July 28, 2015) Docket No. 20000-469-ER-15 Record No. 1407, page 4, lines 9 – 12.
[11] Pre-filed Direct Testimony of Belinda J. Kolb, Ph.D. before the Public Commission of Wyoming. (July 28, 2015) Docket No. 20000-469-ER-15 Record No. 1407, page 8, lines
[12] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 44, lines 5 – 10.

In order for a sharing mechanism to be believed to improve forecasts of net power costs, as stated above, the basis of the adjustment must be a forecast. More concerning than the evidence of GRID's use in design of approved rates is Mr. Higgins' clear denial of the use of forecasts after himself being involved in cases involving RMP and PacifiCorp as an expert witness for various special interest groups.

Q. What is your response to Mr. Higgins' claim that imprudence is not a necessary finding in order to implement a risk-sharing mechanism?

A. In making this claim, Mr. Higgins does not address information regarding fuel procurement and dispatch practices. In order to recommend a change to TEP's PPFAC without examining such data, Mr. Higgins understandably minimizes the importance of findings of actual fact in order to justify his own recommendation. Paradoxically, Mr. Higgins states that a "well-crafted sharing mechanism supports"[13] his hypothesis that TEP will get the "best possible deal",[14] yet fails to provide any analysis for his recommendation of a 70/30 sharing mechanism. A recommendation without evidence nor investigation to support it certainly cannot be considered to be well-crafted.

Q. Do Rocky Mountain Power and PacifiCorp represent the only risk-sharing mechanisms in Oregon, Wyoming, Idaho, Montana, and Wyoming?

A. No. Idaho Power utilizes a Power Cost Adjustment Mechanism ("PCAM"). Idaho Power's PCAM includes both a deadband and an adjustment for a return on equity, neither of which have been proposed by Mr. Higgins. The following paragraph from Exhibit RJR-R-1 describes the inclusion of return on equity in the PCAM:

---

[13] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 43, lines 1 – 2.

[14] Surrebuttal Testimony of Kevin C. Higgins on behalf of AECC and Noble Solutions – Purchased Power and Fuel Adjustment Clause (August 25, 2016), page 42, lines 19 – 20.

> Power supply deviations are calculated using an asymmetrical deadband. A positive deviation (actual expenses greater than those recovered) will be reduced by the dollar equivalent of 250 basis points of Return on Equity (ROE) from Idaho Power's last general rate proceeding. Ninety (90) percent of any excess power supply cost would be deferred for possible recovery. A negative deviation (actual expenses lower than those recovered) will be reduced by the dollar equivalent of 125 basis points of ROE. Ninety (90) percent of any power supply savings would be deferred for possible refund to customers.[15]

Portland General Electric Company ("PGE") also utilizes a deadband and an adjustment for a return on equity. The Public Utility Commission of Oregon ordered:

> "Annual Variance Tariff: The Commission adopts a Power Cost Adjustment Mechanism (PCAM) with an asymmetrical deadband of -75/+150 basis points, and beyond that, an allocation of 90 percent of the variance to customers and 10 percent to the Company. The PCAM will also have an earnings test that allows the Company to recover 90 percent of its power costs up to 100 basis points below its authorized return on equity (ROE), and refund 90 percent of its power costs to customers after the Company earns more than 100 basis points over its ROE".[16]

While TEP is not in favor of the use of a risk-sharing mechanism, particularly in the absences of quantitative analysis, the inclusion of a deadband and considerations for

[15] Order No. 08-238 Entered April 28, 2008, Public Utility Commission of Oregon, Power Cost Adjustment Mechanism Adopted. Page 3, paragraph 4. Exhibit RJR-R-1

[16] Order No. 07-015 Entered January 12, 2007, Public Utility Commission of Oregon. Request for General Rate Revision. Page 2, paragraph 5.

returns on equity in other utilities fuel recovery is representative of a more balanced approach to addressing fuel costs than Mr. Higgins has recommended.

III. MARGINS FROM LONG-TERM SALES CONTRACTS.

Q. Mr. Higgins continues to propose that all revenues from wholesale sales, irrespective of term, be credited against fuel and purchased power costs in the PPFAC. Do you find his proposal to be a balanced approach?

A. No. When coupled with Mr. Higgins' recommended buy-through tariff, and his opposition to the recovery of TEP's lost fixed-cost generation revenues through the LFCR, his proposal is anything but balanced. Mr. Higgins is simply advocating for a lower price for his customers, while stranding costs at TEP to be spread over the remaining retail customer base.

Q. In the last rate case, did TEP change the treatment of long-term wholesale sales in the PPFAC Plan of Administration ("POA") in order to benefit the Company, as Mr. Higgins claims?

A. No. In 2013, TEP made numerous changes to its POA, one of which was to include the definition of long-term wholesale sales. The POA meaning of long-term wholesale sales from the 2008 TEP Settlement Agreement through 2013 relied upon simply referencing numerous long-term transactions which were differing in length. By including the Federal Energy Regulatory Commission ("FERC") definition of long-term sales, the Company sought to bring clarity by incorporating the industry standard definition of the difference between short-term sales and long-term sales. Long-term wholesale sales have received the same treatment since the inception of the Company's PPFAC, there was no change in treatment in 2013.

Q. Does RUCO witness Frank Radigan also propose a sharing of margins on TEP's long-term wholesale power sales with retail customers?

A. Yes. He continues to advocate an 80/20 sharing mechanism, whereby 80% of the margins on new long-term wholesale sales be credited to retail customers.[17] In support of his position, on page 8 of his Surrebuttal Testimony he states as follows:

> It is inequitable for the Company to profit off the sales of generator output that is supported by retail customers. The Company should still have an incentive to make these sales, however, or else they just wouldn't bother and both the utility and ratepayers would be worse off.[18]

Q. Do you agree with Mr. Radigan's recommendation and supporting rationale?

A. No. TEP's retail customers are already benefitting from the allocation of generation costs to the Company's long-term wholesale contracts. This is done in every retail rate case, where the allocation method and underlying data can be subjected to detailed scrutiny. This periodic review process serves to true-up TEP's cost allocation for changes to the Company's wholesale contracts, as well as changes to TEP's retail customer demand, that occur between retail rate cases. Because of this cost allocation process, Mr. Radigan is correct to point out that both TEP and its customers would be "worse off" if the Company did not have any long-term wholesale contracts. In light of this, it is difficult to understand why Mr. Radigan would advocate taking away 80% of the Company's incentive to enter into such contracts. The only possible rationale would be his belief that profits on new wholesale contracts are somehow "inequitable" to TEP's customers.

---

[17] Surrebuttal Testimony and Settlement Testimony of Frank Radigan on Behalf of RUCO (August 25, 2016), page 3, lines 17 – 19.

[18] Surrebuttal Testimony and Settlement Testimony of Frank Radigan on Behalf of RUCO (August 25, 2016), page 8, lines 4 – 11.

Moreover, RUCO continues to oppose the Company's proposed LFCR changes to recover generation costs. This, combined with the proposed sharing mechanism, deprives the Company of any reasonable opportunity to recover its fixed generation costs.

Q. Mr. Radigan expresses concern regarding the treatment of two existing long-term contracts. Do those contracts warrant a sharing mechanism as he proposes?

A. No. On pages 7-8 of his Surrebuttal Testimony he discusses the Company's retention of profits on the Shell Energy contract, as well as the expected increase in sales to TRICO Electric Cooperative in 2018. In the case of the Shell Energy contract, the Company has already committed to treating that contract as a short-term sale for purposes of the 2017 PPFAC, thus fully crediting retail customers for the remaining margins on that contract. As for the TRICO contract, the anticipated increase in sales is not scheduled to occur until 2018, over a year after the expected effective for new retail rates. The scheduled increase in contract demands, from 50 MW to 85 MW, is also quite small relative to TEP's retail demand and overall system size. Between now and 2018, there are many changes that could affect TEP's retail customer demand, the cost of operating and maintaining TEP's generation fleet, and other factors that would normally factor into the Company's jurisdictional cost allocation.

Q. What are the near-term prospects for expanding TEP's wholesale business?

A. The wholesale power market in the Southwest is currently very depressed, due in large part to low natural gas prices and weak customer demand in the region. Although the Company will continue to evaluate new wholesale opportunities as they arise, it is challenging to negotiate profitable long-term wholesale contracts in the current market environment.

Q. Does this conclude your testimony?

A. Yes

REJOINDER TESTIMONY OF

DENISE A. SMITH

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of

Denise A. Smith

on Behalf of

Tucson Electric Power Company

September 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Denise A. Smith. My business address is 88 E. Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct and Rebuttal Testimony in this proceeding?

A. Yes.

Q. Which Commission Staff and/or Intervener testimony do you address in your Rejoinder Testimony?

A. I address the Surrebuttal testimonies filed by Matt Connolly of the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission" or "ACC") on the topic of Prepay Metering; Eric Van Epps of Staff on the topic of a DSM Plan of Administration; Cynthia Zwick on behalf of the Arizona Community Action Association ("ACAA") on the topics of Bill Assistance, Lifeline customers and Prepay Metering; Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP") regarding Prepay Metering; and Sarita Morales and Scott Northrup on behalf of IBEW Local 1116 ("IBEW") on the topic of Customer Service.

II. RESPONSE TO STAFF (Matt Connolly).

Q. Do you have any comment on Staff witness Mr. Connolly's belief that Prepay should be a billing option but not an Energy Efficiency program?[1]

A. The Company respectfully disagrees with Mr. Connolly. Tucson Electric Power Company ("TEP") believes there is a strong case to be made that Prepay is very similar to other behavioral Energy Efficiency ("EE") programs. TEP believes that it is ultimately a policy decision by the Commission whether Prepay provides energy efficiency savings and should be included as a program in TEP's next Energy Efficiency Implementation Plan. Consistent with our other EE programs, the Company has proposed that a third party evaluate this program by identifying and verifying savings which are separate from disconnection and compare our EE program to other like programs around the country.

III. RESPONSE TO STAFF (Eric Van Epps).

Q. Do you agree with Staff witness Mr. Van Epps' recommendation to submit a final POA for the DSM surcharge adjustor within 60 days of a decision in this case?

A. Yes.

[1] Connolly Surrebuttal, 4:4-5.

IV. RESPONSE TO ACAA (Cynthia Zwick).

Q. Does the Company agree with ACAA's request to increase the funding of TEP's current Bill Assistance program from $150,000 to $200,000?

A. The Company believes that its shareholder contribution of $150,000 annually to the bill assistance program in TEP's service territory is reasonable. However, TEP is proposing to commit to this funding level for a five-year period.

Moreover, we recently announced an expansion of our shareholder-funded bill assistance program to reach the communities served by UNS Electric, Inc. ("UNS Electric"). Beginning this year, UNS Electric will voluntarily contribute $50,000 annually for five years to ACAA for the Home Energy Assistance Fund.

These shareholder-funded commitments would provide $1 million of funding to ACAA over the next five years for bill assistance programs in the communities served by TEP and UNS Electric.

Q. Does the Company support automatically enrolling customers in the Lifeline program who receive bill assistance?

A. As stated in my Rebuttal Testimony, to help support the Lifeline program the Company will make every effort to keep assistance agencies supplied with Lifeline enrollment pamphlets that they can provide to all qualifying assistance recipients. Consistent with the recent rate order for UNS Electric, TEP will also investigate how to implement a streamlined, cost effective automatic enrollment process before TEP's next rate case.

Q. Do you agree with the ACAA's recommendations to hold Lifeline customers harmless from deposits?

A. No. TEP believes all customers should be treated identical with respect to deposits. TEP currently does and will continue to work with customers who need financial assistance.

Q. ACAA has expressed the opinion, and cited the opinion of others, that Prepay is not a voluntary program because for some customers the only option might be Prepay or no electrical service, is this a fair criticism?

A. No. Entertaining ACAA's hypothesis that customers might only have a choice between Prepay and no service leads one to conclude that there are those who, presently absent the option of Prepayment, are living without electricity. We do not believe this to be true. If approved, Prepay will be an additional option for all of our residential customers. TEP cannot force a residential customer onto any rate plan.

Q. In Surrebuttal Testimony ACAA continues to express concerns about the methodology by which other Prepay programs have evaluated energy conservation resulting from program participation. Do you believe these concerns are relevant to approving this rate option within this rate case?

A. No. For several reasons: (1) this rate case asks only for approval of the program as a billing option; (2) the proper venue for debating the Program's merits as an energy conservation program is within the DSM planning process; (3) the Company has agreed to conduct a third party evaluation of the program as an energy conservation program should it be approved as such; and (4) it is not the practice of the Commission or Staff to permit the Company to claim conservation savings that are not verified.

Q. Do you agree with ACAA's conclusion that the APS pilot should be "viewed with suspicion" because 63-69% of survey participants were low-income while only 7% of participants in the energy efficiency impact analysis were low-income?[2]

A. No. The survey participant sample referenced deliberately oversampled elderly and low income customer segments pursuant to APS Decision No. 72214, which states "If necessary, elderly and low income customer segments shall be over-sampled in the study to ensure adequate sample sizes for the reliable analysis of the effects and research questions for these customer segments."

In contrast, the participant pool eligible for the energy efficiency impact analysis was dictated by scientific methodology as follows:

- Of 2,131 unique pilot participants, 11 were removed because they moved premises during the program.
- Of 2,120 remaining participants, only 610 had pre-enrollment consumption data.
- Of 610 eligible participants, 86 had sufficient pre- and post- enrollment data for matching against a non-participant control group.

Q. Do you have any comment on ACAA's assertion that there is "no reason to force customers onto prepaid electricity in order to receive [daily] consumption information"?[3]

A. Current customers receive monthly consumption information on their bill. Prepay customers will have the added benefit of receiving daily energy consumption data, along with alerts regarding account balance, which will enable them to better manage their energy use.

---

[2] Zwick Surrebuttal, 21:12-17.
[3] Zwick Surrebuttal, 23:1-2.

Q. Do you agree with Ms. Zwick that reduction in bad debt, carrying costs, collections expenses and write-offs resulting from the Program constitute a "savings" which Prepay participants are entitled to?[4]

A. No, I don't. The reduction of bad debt and collection expenses benefits all of our customers.

Q. Do you agree with ACAA's statement that "levelized billing...is inaccessible to prepay customers"?[5]

A. No. Customers choosing Prepay are opting out of the Company's levelized billing program in favor of taking more direct control of their bill. However, customers have the benefit of choosing the billing option that suits their lifestyle.

V. RESPONSE TO SWEEP (Jeff Schlegel).

Q. Do you agree with SWEEP's conclusion that continuing to recover funding for DSM, but not other energy resources, through an adjustor is neither transparent, nor equitable?

A. No. The Company believes that customer-funded programs that are designed to meet Commission-mandated programs, like the Energy Efficiency Standard and the Renewable Energy Standard, should be collected from customers through adjustor mechanisms. Adjustor mechanisms provide clear line-of-sight transparency to the budget levels for these programs and affords the Commission with the flexibility to adjust funding levels as appropriate. Furthermore, although SWEEP made the same proposal in the UNS Electric rate case, the Commission rejected the proposal and in its order stated, "We

---

[4] Zwick Surrebuttal, 23:8-12.
[5] Zwick Surrebuttal, 23:24-25.

believe that at this time, keeping the DSM adjustor as a separate line item is the best course of action."[6]

Q. Please comment on SWEEP's proposal to separate Prepay as a tariff from the enhanced conservation awareness the program will offer?

A. See response(s) to ACAA above.

VI. <u>RESPONSE TO IBEW LOCAL 1116 (Sarita Morales & Scott Northrup).</u>

Q. Have you reviewed the Surrebuttal Testimony of IBEW witnesses Sarita Morales and Scott Northrup?

A. Yes, I have.

Q. Please respond to IBEW witness Ms. Morales' assertion that the Part-Time Seasonal Customer Service Representatives ("Seasonal CSRs") have caused havoc.[7]

A. I completely disagree with Ms. Morales' characterization.

Q. Why did TEP hire Seasonal CSRs?

A. As mentioned in my Rebuttal Testimony, the Company hired 25 Seasonal CSRs as a pilot program to cost-effectively address the seasonal spikes experienced in call volume during the summer and early fall. This has resulted in a reduction in the average wait time per customer by 60% compared to last summer – a clear benefit to our customers.

[6] Decision No. 75697 (August 18, 2016).
[7] Morales Surrebuttal, 7:20.

In addition, there have been no informal ACC complaints filed by customers relating to wait time as compared with 11 complaints filed last summer.[8]

Q. Please explain how you assure the seasonal workforce meets the Company's quality standards and provides excellent customer service.

A. The Company has taken the appropriate steps to provide training and adequate quality assurance monitoring for the Seasonal CSRs. The classroom training occurs over a two week timeframe and is led by the department trainer. In addition to this training, the Seasonal CSRs are given on–the-job training with the trainer and/or a supervisor for one week. After the training, the Seasonal CSRs are subject to the same monitoring and quality assurance program as our full-time employees. In fact, in studying the quality monitoring scores, the Seasonal CSRs have very similar numbers to a new full-time employee.

As a part of our quality assurance program, customers have the option to complete an after call survey where they give feedback on how the call was handled by their CSR. The scores for our Seasonal CSRs are also very similar to our full-time employees.

For these reasons, the Company believes there is sufficient oversight, quality assurance and training for the Seasonal CSRs. Once this pilot concludes in the fall, it is the Company's intent to evaluate all aspects of the program.

[8] As of August 26, 2016 for both ACC complaints and average speed of answer statistics.

Q. What happens if a Seasonal CSR receives a billing question they can't answer?

A. Billing questions can, at times, be complex. In such cases, those calls are transferred to a more experienced full-time CSR who receive full credit for taking the call. Currently this occurs approximately 8% of the time.

Q. Are UNS Gas emergency calls "bounced around the system" as suggested by IBEW witness Ms. Morales?[9]

A. No. The Company takes the safety of its customers very seriously. IBEW witness Ms. Morales is mistaken about the training provided to Seasonal CSRs regarding gas emergency calls. If a UNS Gas customer requesting a gas emergency inadvertently calls the TEP customer service number, the Seasonal CSRs have been trained to immediately hand the call over to a full-time employee or a member of the management team. There is always a full-time employee or a member of management available to work with the Seasonal CSRs. As of the writing of this testimony, this situation has never occurred.

Q. Explain the process for how full-time employees assist the Seasonal CSRs.

A. Our experienced full-time employees volunteer to assist the new Seasonal CSRs. The feedback from this cross-training process has been positive from both the full-time employees and the Seasonal CSRs. About one-third of our full-time employees have volunteered to assist and answer questions for the new Seasonal CSRs. Contrary to Ms. Morales' testimony, these full-time employees are not penalized for assisting the Seasonal CSRs.[10]

---

[9] Morales Surrebuttal, 8:19-20.
[10] Morales Surrebuttal, 8:11-13.

Q. Do you and other call center management personnel meet regularly with IBEW representatives?

A. Yes. The department managers hold monthly meetings with the union stewards and the union business representative. In addition, a joint management/labor committee was recently established to propose performance metrics. Call center supervisors also meet monthly with union stewards to discuss any issues. Contrary to Ms. Morales' claims, the teams work together in a collaborative and positive manner.

Q. Do you have any other concerns from IBEW that you would like to address?

A. Yes, IBEW witness Mr. Northrup makes unsubstantiated claims about cross-subsidization occurring in the Call Center between TEP and UniSource Energy Services ("UES").[11] While it is possible that a UES customer might call the TEP customer service phone number, we use cost allocation methods that allocate the costs associated with shared resources and systems based on both the underlying customer count as well as call center tracked time to avoid cross subsidization.

Q. Does this conclude your Testimony?

A. Yes.

[11] Northrup Surrebuttal, 5:21-23.

REJOINDER TESTIMONY OF
H. EDWIN OVERCAST

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of

H. Edwin Overcast

on Behalf of

Tucson Electric Power Company

September 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes. I filed Rebuttal Testimony in this proceeding.

Q. Which Intervenor testimony do you address in your Rejoinder Testimony?

A. I will respond to the testimony of witness Kobor of Vote Solar, witness Huber of the Residential Utility Consumer Office (RUCO), witness Zwick of the Arizona Community Action Association (ACCA), witness Higgins of Freeport Minerals Corporation, Arizonans for Electric Choice & Competition and Noble Americas Energy Solutions LLC, and witness Baatz of the Southwest Energy Efficiency Project (SWEEP) and Western Resource Advocates (WRA). Since several of these witnesses cover the same issues, at some points I will refer to them collectively for ease of discussion.

Q. How is your testimony organized?

A. My testimony addresses the use of the minimum system for classifying costs associated with distribution system costs in FERC accounts 364-368 between a customer and a demand component. The parties who oppose this cost classification have chosen to either ignore the evidence related to cost causation for these accounts or have made fatal errors in their analysis of the evidence before the Arizona Corporation Commission (Commission) that provides the factual basis for use of the minimum system. Opposition to the use of the minimum system is simply not consistent with the principle of cost causation as my Rebuttal Testimony has shown. I also discuss why it is both necessary and appropriate to raise the monthly customer charge for rates to be efficient, cost-based and just and reasonable. Cost-based rates, as a matter of principle, is a requirement for rates that satisfies the U.S. Supreme Court mandate that rates provide the utility a reasonable opportunity to earn its allowed rate of return.

I will also address issues related to energy price signals and conservation that have been the subject of the surrebuttal testimony of several witnesses. The claim that raising the utility's monthly customer charge will result in decreased energy conservation is not credible unless the only definition of conservation is reduced use, and that is not the definition of conservation. As I discussed in my rebuttal testimony the actual definition of conservation follows: "Conservation is the act of preserving, guarding or protecting; wise use."

II. <u>COMMENTS ON WITNESS HUBER'S SURREBUTTAL TESTIMONY.</u>

Q. Witness Huber asserts that you are incorrect when you state that the basic customer method is inconsistent with the NARUC Electric Cost Allocation Manual (NARUC Manual). Please comment on that assertion.

A. Witness Huber's assertion is completely contrary to the contents of the NARUC Manual for a number of reasons. For example, the basic customer method is not even discussed in the NARUC Manual. In fact, the NARUC Manual states the following related to the classification of distribution system costs between customer and demand.

> Distribution plant Accounts 364 through 370 involves demand and customer costs. The customer component of distribution facilities is that portion of the costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are

directly related to the number of customers on the utility's system.[1] (Emphasis added.)

There is no ambiguity in this statement and it is certainly evidence that the NARUC Manual does not support the use of services and meters as the only customer-related plant costs. Thus my conclusion relative to the basic customer method is completely accurate. More importantly, my Rebuttal Testimony has provided the critical lynchpin between customer and demand costs by empirical analysis that shows the equipment in Accounts 364 through 368 are directly related to the number of customers served by the utility. That conclusion is not based solely on my own evidence, but it is also supported by empirical analyses conducted for estimating total factor productivity in utility rate cases.

Q. Does witness Huber find fault with your empirical analysis?

A. Yes. Witness Huber claims that neither analysis "succeeds in proving cost causality." The basis for his conclusions related to cost causality in the regression analysis I presented is the concept of "omitted variable bias". Essentially, this is an argument that the independent variables specified in the regression analysis omitted a critical model variable and thereby produce a result that is biased. However, the discussion of this potential problem ignores the conditions necessary to reach the conclusion that a critical variable has been omitted. Two conditions must hold true for omitted-variable bias to exist in a linear regression: 1) the omitted variable must be a determinant of the dependent variable (i.e., its true regression coefficient is not zero); and 2) the omitted variable must be correlated with one or more of the included independent variables (i.e. cov(z,x) is not equal to zero). Witness Huber does not agree that his list of other variables meets either of these two tests. There is also a variable omitted in the model specification. For example, witness Huber postulates that kWhs are relevant and should

[1] NARUC Electric Utility Cost Allocation Manual, p. 95.

have been included in the analysis. However, there is no possible basis for inclusion of kWhs in a properly specified model of cost causation. KWhs cannot cause distribution investment since a causal variable must precede the dependent variable and kWhs are not known until after the delivery facilities are installed. That installation is based on two independent measures- the existence of the customer on the utility's distribution grid and the maximum demand of that customer. There are no other variables omitted from the model since these are in fact the independent variables used to develop the utility's delivery system. Thus there is no evidence of omitted variable bias. The model is properly specified and meets all the required statistical tests to demonstrate that both demand and customers cause the investment in FERC accounts 364 through 368. The first analysis I presented is conclusive as to cost causation.

Q. Please comment on the analysis used by witness Huber to dismiss the transformer analysis used in your Rebuttal Testimony to demonstrate that only with the minimum system analysis can delivery costs allocated among the customer classes reflects cost causation.

A. Witness Huber makes two arguments he claims prevent the use of this analysis. First, he argues incorrectly that the physical count of transformers used by the residential class may not reflect the total cost of those transformers. For purposes of demonstrating the physical allocation of transformer assets, the cost is not particularly relevant to the argument that Non-Coincident Peak (NCP) under allocates the number of transformers to residential customers. The cost becomes important when developing the class revenue requirements and the residential class receives a pro-rata share of the total costs. This means that the allocated share of transformer costs for the residential class is actually lower than the cost of the physical transformers simply because of economies of scale that result in a higher cost per kVa of transformer capacity for smaller, single phase transformers used by residential customers. This is not a flaw in the analysis but a benefit that results from average costing in the utility's cost of service study. His argument makes the results of the minimum system conservative relative to actual costs, and therefore must be rejected as an argument against the minimum system cost classification.

The second argument against the analysis is that transformers may be used by more than one class. There are two problems with this statement. First, nearly all residential transformers are single phase and step down to secondary voltage. Thus most transformers are uniquely serving the residential class alone. Where the transformers serve small commercial customers also, the transformer is considered residential only if more than half of the load is residential. Thus, the estimate of the physical number of transformers serving residential customers is based on actually serving residential load. Use of the basic customer charge method allocates these costs predominantly to larger customer classes who account for more NCP demand but do not even cause the costs for single phase secondary transformers. Witness Huber is incorrect in his criticism and hence has not shown by evidence that customers are not the cause of these delivery costs. The only remaining conclusion is that it is the so called basic customer method that cannot and does not reflect cost causation and therefore must be rejected as a measure of the allocated customer costs for the utility's delivery system.

Q. Witness Huber states that RUCO's position is that any cost that is shared between customers should not be included in fixed charges. Please comment on this position.

A. There is no basis for this position other than an opinion consistent with the basic customer method that is unsupported by any evidence of cost causation or even support from any rigorous analysis of cost of service and rate design. The fact that fixed charges are calculated including shared cost is sufficient to demonstrate that equitable rates require fixed cost recovery in fixed charges in order for rates to be just, reasonable, not unduly discriminatory and to fairly recover the apportioned costs. The argument that fixed charges must be used to recover fixed costs is firmly established for numerous reasons as I have explained in my Rebuttal Testimony and in the paper provided as Appendix B to that Rebuttal Testimony. The average customer cost from the utility's cost of service study is based on a mix of shared and dedicated facilities and represents the average customer cost across the class of service.

Q. Witness Huber discusses the matching principle and claims that among other things it is not related to rate design and the minimum system violates the matching principle. Please comment on these claims.

A. Witness Huber cites to an American Public Power Association (APPA) report that no rate design will result in a perfect matching of rates and costs. That conclusion is wholly consistent with my views on the matching principle and has no role in determining the conclusions I have drawn about the matching principle as it relates to rate design. As I have pointed out, each customer has a different actual cost by virtue of such factors such as the side of the street the customer is served on or the age of the facilities that serve the customer. There are other factors discussed in my Rebuttal Testimony such as urban and rural costs, overhead and underground costs and so forth. The matching principle is not based on perfection for each customer simply because rates are based on average costs for a class - not the actual costs for each customer. Matching is however an important ratemaking principle for both revenue requirements in the rate effective period and the design of rates necessary to provide the utility with a reasonable opportunity to recover revenue requirements from customers in a way that provides the utility with a reasonable opportunity to recover costs from those customers who cause the costs. Without matching, no rate design can meet the requirement that the utility has a reasonable opportunity to earn the allowed rate of return and that an individual customer pays the average cost imposed on the utility's delivery system. Both of these concepts are not addressed by witness Huber in his rate design proposals so it is not surprising that he would find this principle problematic.

Q. How does witness Huber ignore these principles in rate design?

A. Witness Huber ignores both of the cost causation and the matching principles by supporting rates that recover nearly all fixed costs in ever increasing kWh charges or non-cost based TOU price signals coupled with as low a customer charge as his basic customer method will support. A two-part rate cannot track costs unless a customer class is homogeneous. Residential customers are no longer homogeneous or even close to that standard with the introduction of distributed energy resources. Currently customers have load factors as low as zero and as high as above 40 percent. It is impossible for any two part rate- TOU or otherwise- to match costs and revenues during a rate effective period for customers who have this large a variance in consumption patterns. For example, no two customers have the same on-peak kWh use. Under witness Huber's proposed rates, the on-peak hours recover a significant portion of the utilities fixed costs that do not vary with kWh use. Thus if kWh use drops in response to a high on-peak price signal, the utility is deprived of any opportunity to earn the allowed rate of return since its change in revenue under witness Huber's rate design declines by much more than the actual decline in costs. That equals lost return for each cent that costs decline by less than the revenue. The problem is also exacerbated by the differences in customer load factor because the incentive for high load factor customers is to use less energy resulting in a less efficient use of productive resources. That outcome is also inconsistent with the rate design provisions under the Public Utility Regulatory Policies Act (PURPA) where the proposed rates totally fail to meet two of the three purposes of PURPA: the optimization of the efficiency of use of facilities and resources by electric utilities and equitable rates for electric consumers.

Q. Witness Huber claims that your hypothetical example of the failure of two-part rates to track costs when customers are not homogeneous is so flawed that it proves nothing. Please comment.

A. His observations about my simple example are simply wrong. To start, witness Huber states a premise for the example that I have assumed all fixed costs are customer-related and then proceeds to demonstrate that the hypothetical with his modification produces an unacceptable result. In fact, there is no assumption that costs are customer- related since the assumption is that the customers have identical demands that cause all non-customer or energy-related costs to be the same. By adding a third customer as suggested by witness Huber that has the same demand and different energy characteristics, the example still holds that customers with less than the average energy level for the class will pay less for demand-related costs and be subsidized by the higher than average energy user. I might add that one reaches that same conclusion even if the energy rates are time-differentiated. Using energy charges to recover fixed costs (customer or demand) always creates an intra-class subsidy. That conclusion is unavoidable unless the customer in that class all has equivalent load factors and common peak demands.

Q. Witness Huber argues that competitive businesses with high fixed costs recover those costs volumetrically and hence there is no basis for fixed charges. Please comment.

A. As I discussed in detail in my Rebuttal Testimony, this is a common argument made by opponents of fixed charges. The argument has been shown to be false repeatedly beginning as early as the 1930s and as recent as June of this year. I will not repeat the discussion from my Rebuttal Testimony here except to say that witness Huber continues to make an argument that is not supported by utility ratemaking principles.

Q. Witness Huber argues that fixed charges are inefficient. Please comment.

A. The basic economic proposition for efficient pricing is that per unit price equals short-run marginal costs. There is no dispute in economic theory about this conclusion. I have discussed the economics of efficient pricing in detail in my Rebuttal Testimony in a discussion of the seminal work of Ronald Coase in laying out the principles for efficient pricing. The argument is simple and basic. Set the marginal price at marginal cost (the short-run value is the efficient price) and recover the remaining revenue requirement in a fixed charge. The fixed charge is a residual value and is efficient under two conditions: the marginal price equals marginal cost and the total revenue requirement of the utility is recovered. Witness Huber is correct in this case just not for the reason he states. He is correct because the marginal price signal far exceeds marginal cost and Tucson Electric Power Company (TEP or the Company) does not recover its revenue requirements. In essence, an efficient customer charge would need to be higher not lower since the marginal price exceeds marginal costs.

Q. Witness Huber makes a number of observations related to the use of the OpenEI Utility Rate Database. Please comment.

A. First, as with any database one must use the data carefully. While the data base does contain much more than just residential rates, it is relatively easy to sort out residential rates from all of the other utility rates. My report used only current residential rates as reported in the database. Further, I have collected similar data on my own from current rate schedules for other utilities over the years, by state, and am able to confirm the conclusions independently for utilities in a number of the states. The criticisms of witness Huber are incorrect because the data represents current residential rates for the utilities used in the analysis. The data shows that higher monthly customer charges are much more common than witness Huber and others in this case want to believe thus destroying the fundamental narrative that higher fixed charges are inappropriate. They are not.

III. COMMENTS ON WITNESS BAATZ'S SURREBUTTAL TESTIMONY.

Q. Please comment on the testimony of Witness Baatz of SWEEP and WRA. Are the utility regulatory commission citations he provides in support of moderating the Company's proposed customer charge level relevant?

A. Absolutely not. The decisions he cites are from proceedings in which the fact bases are entirely different or difficult to compare with the Company's facts in this proceeding; in some cases these decisions are based on erroneous interpretation of NARUC guidance; or are simply policy level decisions to which the Commission has to obligation to adhere. Witness Baatz merely selects a handful of decisions that appear to endorse ameliorating of proposed customer charge increases for specific facts and policy level considerations relevant to that proceeding/jurisdiction and suggest they represent a body of evidence as to a far reaching national precedent that should somehow apply to the facts in this case before the ACC.

Q. Please explain.

A. Consider the cite from the Michigan Public Service Commission (MPSC) in the DTE Electric Company proceeding: "In addition, as the Staff observed, the NARUC Manual likewise supports using only the marginal costs of customer attachment in developing a customer charge." There is no language in the NARUC Manual that could reasonably be interpreted as direction from NARUC requiring utilities to use the marginal costs of attachments alone to compute a customer charge. The NARUC Manual states that this is one of two options for analysts and that the other includes the minimum distribution system. In this particular order, the MPSC relied on an incorrect interpretation of the

NARUC Manual as part of its support in its decision. It further ignored the preamble to the chapter on marginal transmission, distribution and customer costs that includes the following statement: "'… the determination of marginal costs for these functions and especially for distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort.'" The decision of the MPSC was purely a policy level decision guided in part by choosing one potential view of NARUC guidance on the matter of the proper determination of customer costs. The Commission is under no obligation to adhere to policy decision by the MPSC and should ignore this decision.

Q. Please comment on the relevance of the decision issued by the Minnesota Public Utilities Commission (re: Northern States Power Company) contained in Witness Baatz's Rebuttal Testimony.

A. As is the case for all of the decisions cited by Witness Baatz regarding the customer charge topic, this is based upon a particular set of facts that differ from those of the Company in this proceeding. Consider the passage in his cite: "This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability." Although Witness Baatz chose not to emphasize this sentence in this cite, I believe this passage highlights the key reason this decision is not applicable in this proceeding. That is, according to this cite, one of the key considerations of the MPSC in reaching its decision to not increase the customer charge in this particular proceeding was that Northern States Power Company had an approved revenue decoupling mechanism. This is not the case with the Company – although the Company has an LFCR in place – the revenue recovery potential is limited as compared to the one described in this decision. Again, this key difference highlights the problem with hand-picking a few orders from proceedings with different facts and suggesting they represent a broad policy consensus. In fact, nearly all the states from which Witness Baatz provides regulatory decisions that support limited to no customer charge increases are from jurisdictions with revenue decoupling in place. On this basis alone, they should all be ignored.

Q. Please comment on the 2007 order issued by the Illinois Commerce Commission (Commonwealth Edison Company) that Witness Baatz cites in his rebuttal testimony.

A. Witness Baatz cites an order that appears to reject the use of the Minimum Distribution System as the basis for supporting a certain customer charge level. What is interesting however to note, is that since 2011 Commonwealth Edison Company has been setting rates under a Formula Rate Plan (FRP) approach; this approach is essentially an annual rate setting process that allow for rate recognition for certain company investments; a formula set by legislation for determining annual ROE; certain reconciliation adjustments to account for differences in revenue requirement based on timing of data availability in any given year; and other features. The approach is a dramatic departure from the former traditional test year approach (used in 2007) in which revenue requirement is set on a specific test year and rate recovery is achieved only after an extended rate proceeding. In effect, although the FRP is different than a revenue decoupling approach, there are features to the plan that reduce the risks of fixed cost recovery for a large portion of capital investments ($1.3 billion over 10 years). The regulatory construct for Commonwealth Edison has changed dramatically since 2007. This fact alone disqualifies this order from having any relevance to the question of the proper customer charge level for the Company in this proceeding or in the state of Illinois at this time for that matter. However, even if the Commission chooses to consider this data point, it should recognize that the introduction of the FRP relieves some of the need of a higher fixed customer charge to address fixed cost recovery.

Q. What is the relevance of all of these decisions in this case?

A. These decisions provide nothing more than a variety of views on the issues in this case. They set no precedent for the Commission simply because it is the evidence in this particular case that must form the basis of the decision. With respect to the minimum system and the residential customer charge, that evidence proves conclusively that the use of the minimum system is a necessary condition for reflecting cost causation both within and between classes of service. The evidence also fully supports the customer charge supported by Staff and the Company.

Q. Please comment on Mr. Baatz's claim at page 14 of his Surrebuttal Testimony that, "State commissions nationwide are rejecting utility proposals to increase fixed charges as bad public policy."

A. Mr. Baatz's claim is simply misleading and one-sided since it is not indicative of the nationwide trends I have observed related to the regulatory treatment of the monthly customer charges proposed by electric utilities applicable to residential customers. In support of his claim, Mr. Baatz has provided highlights of four (4) rate case decisions in the states of Michigan, Washington, Minnesota, and Illinois in which the regulator in each state has decided to moderate the increase in the monthly customer charges proposed by the electric utility. Unfortunately, these select regulatory decisions fail to provide a fair representation of the very different conclusions in this matter reached by utility regulators in other states.

In a number of states, regulators have determined the importance of increasing monthly customer charges to reflect the fixed cost nature of the electric distribution business in an effort to establish just and reasonable rates for the utility customers. For example, in a recent rate case of Madison Gas and Electric Corporation ("MGE"), the Public Service Commission of Wisconsin approved an increase in the electric utility's residential customer charge from $10.44 to $19.00 per month. The Commission based its rate design decision on the following considerations:

- "Where a particular rate design collects a significant portion of the utility's fixed costs through the variable energy charge, this results in higher-use customers subsidizing lower-use customers regardless of the reasons those customers may have lower use. To the extent a customer reduces usage via energy efficiency, conservation or renewable generation, the customer reduces his or her contribution to the utility's fixed costs and these costs must be picked up from other customers."[2]
- "In this case, the Commission agrees with MGE that an appropriate fixed charge should better align the charge with the fixed costs of providing service, regardless of the amount of energy used or demand placed on the system by the customer. The regulated utility ratemaking process is intended to simulate a free market for monopoly utilities. When rates are properly designed, the rate structure signals to customers the actual cost of providing both backup service and electricity to each class. If the fixed charge is too low, the customer will receive an incorrect price signal that the cost to provide access to the electric system is lower than it actually is to the utility. They will also receive an incorrect signal that the variable cost to provide energy is higher than it actually is to the utility. Setting price signals correctly is important because those signals influence customer behavior, which in turn influences how the utility incurs costs."
- "MGE provides a compelling case that its fixed charges are insufficient to recover its fixed costs. As a result, the variable energy charge is correspondingly too high. The result is a price signal that tells customers that the economic benefit of conservation is higher than it actually is."[3]

---

[2] Public Service Commission of Wisconsin, Docket No. 3270-UR-120, Final Decision, dated December 23, 2014, pages 38-39.
[3] Ibid, p. 39.

- "More importantly, however, the purpose of rate design is not to subsidize the payback of energy efficiency measures or renewable energy. The purpose of rate design is, fundamentally, to connect the rates that customers pay to the costs the utility incurs. Such an approach appropriately encourages efficient utility scale planning."[4]
- "This Commission continues to support customers who want to own their own generation; however, the Commission also has an obligation to those customers who do not want, or who cannot afford, to own generation to make sure these customers are not subsidizing the costs for those who choose to do so."[5]
- "To the extent fixed costs are recovered through the variable energy charge, more fixed costs are paid by higher energy users within a class. The Commission finds that the most equitable result is to better align fixed charges with the fixed costs to serve a customer so that, as best as can be determined in a reasonable regulatory environment, members in a class pay for their fair share of the cost of service."[6]

I should point out that the Commission reached a very similar conclusion on rate design in the rate case filed around the same time by Wisconsin Public Service Corporation.[7] The Commission increased the utility's residential customer charge from $10.40 to $19.00 per month.

In a recent rate case of Sierra Pacific Power Company (d/b/a NV Energy), the Public Utilities Commission of Nevada approved an increase in the utility's residential customer charge from $9.25 to $15.00 per month.[8] The Commission based its rate design decision on the following considerations:

---

[4] Ibid, p. 40-41.
[5] Ibid, p. 41.
[6] Ibid, p. 43.
[7] See the Final Decision dated December 18, 2014 in Docket No. 6690-UR-123 (Wisconsin Public Service Corporation).
[8] Public Service Commission of Nevada, Docket Nos. 13-06002, 13-06003 and 13-06004.

- "The Commission continues to support movement toward cost-based rates and the elimination of intra-class subsidies. If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable. It is appropriate to move the BSCs [Basic Service Charges] closer to their corresponding cost bases in order to establish appropriate price signals and avoid intra-class subsidies.
- While the increase in BSCs will have a corresponding decrease in the energy component of rates, this decrease is not enough to discourage conservation. The residential and small commercial customer classes will continue to control a significant portion of their bills by engaging in activities to reduce their electric consumption while the overall billing is better aligned with the costs SPPC incurs to provide service. As the BSCs for residential and small commercial customers continue to move toward cost-based rates, these customers will have more accurate price signals to inform their conservation activities."[9]

Finally, the Public Utilities Commission of Ohio (the "Commission") recently conducted a three-year long proceeding related to aligning electric distribution utility rate structures with the state's public policies to promote competition, energy efficiency, and distributed generation.[10] The regulator reached the following conclusions on rate design:

- "Initially, the Commission notes the importance of aligning cost causation with cost recovery in order to further Ohio's policy goals of competition, increased energy efficiency, and encouraging distributed generation pursuant to Section 4928.02, Revised Code. The Commission believes that, given the comments filed in this proceeding, as well as recent experience by the natural gas utilities, the rate

[9] Ibid, Modified Final Order, dated January 29, 2014, pages 183-184.
[10] The Public Utilities Commission of Ohio, Case No. 10-3126-EL-UNC.

structure that may best accomplish these policy goals is the SFV rate design (emphasis added).

- Based on findings the Commission made in previous rate cases in which it approved an SFV rate design for all gas distribution utilities on Ohio, "the Commission found that the SFV rate design would produce more stable bills for customers, that bills would be easier to understand and would produce a more accurate price signal, and that the SFV rate design would assure a more equitable allocation of distribution system costs to cost-causers. The Commission believes that these same characteristics could be applicable to an SFV rate design for electric utilities."[11]

Contrary to Mr. Baatz's claimed portrayal, the regulatory decisions across the U.S. associated with increases to the monthly customer charges for electric utilities are much more balanced and reflective of the costing and pricing considerations deemed to be most important by the Company.

Q. Witness Baatz concludes that the Company's proposed customer charge increases are not cost-based. Please comment.

A. As I have shown in detail in my Rebuttal Testimony and above relative to the basic customer method, it is witness Baatz who fails to provide evidence that supports this conclusion. I have shown that the method used to determine customer costs is both sound and accurate. The evidence supports the minimum system method based on theory, good utility practice, engineering, operations, over 100 years of detailed cost analysis from the best minds in the industry including early pioneers in developing the business, empirical analysis and the evidence for the Company in this case. There is no evidence offered by any of the opponents of the cost allocation or rate design that proves there is a better or

[11] Ibid, Modified Final Order, dated January 29, 2014, pages 183-184.

more appropriate cost analysis. In fact, at its core, witness Baatz and others ultimately rely on their preferred results as the basis for opposing the increase. Those preferred results include higher kWh charges even though the charges exceed marginal cost and lower customer charges designed to continue intraclass subsidies from large use customers to small customers on some definition of fair rates. There is no basis for accepting these misplaced arguments that perpetuate inequitable rates for all customers in a class of service.

Q. Witness Baatz makes the claim that increasing fixed charges "violates the primary ratemaking principle of designing rates to discourage wasteful use of public utility services." Please comment on this claim.

A. First, witness Baatz has misstated the Bonbright principle. Correctly stated, the principle is the "Consumer Rationing" principle that states "rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationship between the private and social costs incurred and benefits received." Second, this principle is an economic principle that is founded in marginal cost pricing. It is wasteful use of public utility services if and only if the marginal cost of an additional service is more than the price. Witness Baatz has not even recognized the fundamental meaning of this principle and no evidence has been provided to even show that the marginal cost of additional service is greater than the current price of service, much less the proposed price of service. The facts are quite different. Third, the price exceeds marginal cost by a substantial amount since the savings for the utility from energy efficiency are less in every case than the lost revenue. If the opposite were true, energy efficiency would result in increased earnings for the utility because costs would decline by more than revenue. Fourth, the requirement is symmetrical to promote all use that is economically justified. Current and more importantly proposed rates exceed marginal cost and thus discourage use that is economically justified. Fifth, as noted above, this view, that is pervasive among those who oppose the customer charge increase, violates two of the three purposes of PURPA as they relate to rate design standards. As such, this type of unsupported statement is not evidence, but rather is ill-informed opinion inconsistent with the basic principles of utility ratemaking.

Q. Does witness Baatz make the same argument about fixed charges not being used in competitive markets as discussed above related to witness Huber?

A. Yes. As I note above this argument is both false and irrelevant. I will not repeat my Rebuttal Testimony here and the discussion above except to say that it seems opponents of customer charges that recover the fixed costs of delivery service follow the dictum that if they make the argument often enough it will somehow become true. It will not.

Q. Please comment on witness Baatz's view that recovering fixed customer costs in a fixed charge "collects distribution plant costs evenly for all residential customers without consideration of the differences in costs to serve those customers."

A. Witness Baatz is correct with respect to distribution costs classified to customers, but not with respect to all distribution plant costs. The fundamental cost concept in ratemaking is the recovery of class average costs. As I have discussed in detail, no rates track fixed costs precisely, but an average cost applied to all customers is just and reasonable and not unduly discriminatory. In fact, every customer has a different actual cost for both the customer and the demand components of distribution costs. However, in making his argument, witness Baatz bases his costs on unsupported statements about subgroups of customers within the class. For example he incorrectly assumes that urban customers are less costly to serve than rural customers but provides no evidence to support that assumption. As I show in my Rebuttal Testimony, that is clearly not the case. He assumes that apartment dwellers are less costly to serve than single family customers. He offers no evidence for the validity of this assumption for the simple reason that there is no evidence that demonstrates this is generally true and in fact the opposite may be true in some cases if one actually identifies the factors that cause costs. As a practical matter, there is no attempt to define costs down to individual or subgroup levels simply because using average costs is a reasonable and universally accepted basis for designing a utility's rates.

Q. Witness Baatz claims that TEP's customer charge proposal violates the Bonbright principle of gradualism. Please comment on that claim.

A. As in other rate cases, witnesses quickly choose to quote Bonbright without an understanding of the full context of his principles. Bonbright specifically recognizes that all of his principles cannot be implemented in the real world at the same time because they conflict with one another and gradualism is an excellent example of a principle that causes regulatory conflict. A simple example illustrates this point. Gradualism, as defined by Bonbright does not even state that principle is absolute because he refers to a "minimum of unexpected changes". A minimum is far different from none as proposed by witness Baatz. The principle also conflicts with cost fairness and equity as demonstrated conclusively in this case. The principle also conflicts with compensatory rates that are subsidy free simply because the current customer charge causes low use customers to be subsidized by high use customers. Finally, the concept of gradualism is not fairly measured by a percentage increase as noted by witness Baatz. I have discussed this concept in my Rebuttal Testimony and I will not repeat that discussion here.

Q. Is witness Baatz correct in his conclusion that a high customer charge is antithetical to energy efficiency and conservation?

A. No. As I show above the opposite is true. It is the low customer charge rate resulting in a marginal price far above TEP's marginal cost that is antithetical to energy efficiency and conservation simply because it induces wasteful investments that provide far less customer benefit than the expected benefits based on rates in excess of marginal costs. Customers, who base their decisions on kWh rates above marginal cost, waste valuable resources. Those same dollars could be used to produce a higher return elsewhere in their household budget.

Q. Please comment on witness Baatz's claim that TEP's proposed rate design will increase consumption in its service area.

A. If rates above marginal cost promote increased consumption that would imply that such use is economically justified (part of the Bonbright principle on consumer rationing). In that case, all of TEP's customers benefit since that extra revenue would reduce the frequency of rate cases and reduce rates for customers over time. As for the claim itself, the evidence cited by witness Baatz is not sound. In a 2012 paper by Koichiro Ito of Stanford University he found that customers respond to the total bill rather than marginal energy prices. This means that the non-linear energy prices under the inverted block rates are not useful as a tool to promote energy conservation. This is further evidence that the insistence of witness Baatz and others that the rate design will promote energy use is not possible when bills actually increase. The findings in this article are not new and have been replicated over the years in various studies.

IV. <u>OTHER WITNESSES.</u>

Q. Witness Kobor opposes any customer charge increase. Please comment on her opposition.

A. Witness Kobor offers no new evidence in her support of applying all of the increase to the kWh charge. I believe this position is totally self-serving for solar DG advocates. She has not offered any evidence that supports the basic customer method for customer cost allocation purposes and I have addressed the issues of that method in detail above and in my Rebuttal Testimony. I will not repeat that evidence here. I will merely point out that witness Kobor has not provided anything new to support her conclusion and her recommendation of no increase is based solely on a discredited methodology.

Q. Does witness Zwick properly characterize your Rebuttal Testimony?

A. No. Witness Zwick creates an argument that is not in my Rebuttal Testimony and then refutes the argument. In my Rebuttal Testimony, I merely show that the process used by witness Zwick to estimate eligible low income customers for purposes of criticizing the TEP participation rate is flawed. In simplest terms the data used to estimate the eligible population includes low income individuals or households that are not poor. This is a common problem working across databases to estimate electric customers who qualify as poor. Second, I point out that not all poor, low income customers have electric bills. That point has nothing whatsoever to do with master meters. Instead it recognizes group homes and other institutional living arrangements where persons below the poverty level have no electric bill.

Q. Witness Zwick disputes your conclusion that correlation between use and income is weak. Please comment on his position.

A. The concept of weak correlation does not mean there is no correlation between income and use. It simply means that the distribution of regular bills and low income bills demonstrate that there are small differences between the two groups. Using that weak correlation as a basis for public policy related to electric bill assistance, represents a policy that is ineffective and costly compared to a more targeted approach. It is easy to see that conclusion by looking at the number of eligible low income customers whose bills are among the highest bills for the Company as a whole.

Q. Witness Higgins claims that TEP erred in calculating the load factor for the 4CP/AED cost allocation methodology because TEP did not calculate the load factor based on a single peak. Please comment on that assertion.

A. Witness Higgins is incorrect in his assertion. The system load factor that is properly used is defined by the peak – 4CP in this case. In referencing the NARUC Manual calculation as the basis for his conclusion that AED allocation is based on a single peak. If multiple peaks are used as in this case the weighting for average demand is based on the load factor consistent with the identified peaks. Thus the system load factor would be determined in this case based on the 4CP demand. In part, that is why the methodology is identified as 4CP. The logic used by TEP is sound for using the same measure to determine both load factor and excess demand and the weights for each component. If the total demand on the system is relative uniform AED would be based on 12CP and the load factor would be the 12CP load factor and so forth. By using a single peak to calculate the weight of the average demand component and calculating the average demand on a single CP there is a logical inconsistency between the measure of the average and excess components for the system and the weighting applied to those components. The TEP calculation method properly matches the measures of average demand and the weight used for that measure. Witness Higgins failed to understand the significance of the 4CP component in the development of the allocation factors under 4CP/AED. His assertion should be rejected.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

REJOINDER TESTIMONY OF

CRAIG A. JONES

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of

Craig A. Jones

on Behalf of

Tucson Electric Power Company

September 1, 2016

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Craig A. Jones and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. Did you file Direct Testimony and Rebuttal Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rejoinder Testimony in this proceeding?

A. My Rejoinder Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or "Company").

II. SUMMARY OF TESTIMONY.

Q. In general, what are the issues presented in the recently filed Surrebuttal Testimonies by the other parties in this case that you wish to address?

A. My Rejoinder Testimony will:

1) Present the Company's proposed non-DG rate design that it is willing to accept, as a package, based on: (a) the evidence submitted in this proceeding to date (with DG-specific rate design being addressed in Phase II of this proceeding), and (b) the recent results of UNS Electric's recent rate order (Docket No. E-04204A-15-0142, Order dated August 18, 2016). These rates reflect; (a) the final revenue requirement increase of $81.5 million settled on by various parties to this rate case; (b) the Company's slightly modified revenue allocation method; (c) a $15 per month basic service charge for standard residential customers and a $27 basic service charge for standard Small General Service ("SGS"); (d) a reduced $12 and $22 basic service

charge for the non-standard residential and SGS rates, respectively; (e) proposed changes to residential Time of Use ("TOU") rates; and (f) the elimination of the Super Peak rate;

2) Restate the importance and appropriateness of recovering through the Lost Fixed Cost Recovery ("LFCR") mechanism all Commission-approved revenues lost as the result of the Commission's Energy Efficiency ("EE") and Distributed Generation ("DG") mandates;

3) Discuss the continued concerns the Company maintains relating to the pending Buy Through rate and the AECC's eleventh hour proposed alternative;

4) Discuss why demand charges and ratchet mechanisms are both reasonable and common mechanisms used to recover fixed utility costs and why the self-serving positions expressed by the solar advocates are both misguided and detrimental to our large high load factor customers;

5) Provide a brief discussion on why the increased basic service charge is otherwise completely cost based and appropriate and is not reducing the customer's incentive to conserve; and

6) Briefly address a number of issues in which certain parties have expressed concerns, including the Lifeline rates; the Master Metered Mobile Home Park ("MMMHP") rate; the Class Cost of Service Study ("CCOSS"); the new Residential Community Solar rate; and the addition of an incremental meter charge for new net metering customers, consistent with the final decision in the recent UNS Electric rate case updated with TEP marginal cost data. This last section will also briefly discuss Wal-Mart's subsidy mitigation proposal, migration language in the SGS tariffs, grandfathering of migrating customer's rate design, tariff parameters, the Demand Side Management ("DSM") recovery method and the Prepay rate.

Time constraints allow only a limited group of issues to be addressed in this Rejoinder Testimony. The Company reserves the right to address any other issues it deems unacceptable if it so chooses at a later time if necessary.

III. OVERVIEW OF RATES, REVENUE ALLOCATION AND BILL IMPACTS.

Q. Would you please provide an overview of the more notable adjustments that the Company is proposing in its Rejoinder Testimony as it relates to rate design?

A. Yes. Most of the changes being proposed by the Company at this time relate to full requirements customers and are consistent with the Company's Rebuttal position except for minor changes to the residential and SGS customers' basic service charges and other conforming changes to reflect the reduced revenue requirement agreed to by TEP and a number of other parties.

Based on the results of the UNS Electric rate case, TEP is proposing to modify its TOU rates to reflect on-peak periods of 3:00 – 7:00 pm during the summer months and 6:00 – 9:00 am and pm in the winter months for the residential rate classes starting with the rate effective date of this proceeding. Since two tiers were approved for rates in the UNS Electric proceeding and Staff has agreed to two tiers in this proceeding, TEP is willing to offer a slightly lower customer charge for the standard residential customers as part of its Rejoinder position. This reduction to $15 per month is only appropriate if the two volumetric tiers are accepted for the residential rate class. Additionally, the Company is proposing a $3.00 per month reduction to the standard residential and a $5.00 per month reduction to the standard SGS basic service charge for the optional TOU and 3-part rates being proposed for these rate classes. The reduced basic service charges will be $12 and $22 per month for the residential and SGS optional TOU, 3-part standard and 3-part TOU rates, respectively.

Consistent with the recent UNS Electric decision, the Company is also proposing to work with Staff and other Interveners to develop a customer communication and education program to promote greater participation in TOU or three-part rate programs. In addition, the Company will begin to use the optional 2-part TOU rate as the default rate for all new customers from the date new rates take effect in this proceeding.

Further, by immediately implementing the shorter on peak TOU periods the current Super Peak tariff is no longer needed. Therefore the Company is proposing to cancel the Super Peak rate.

I have attached the following **Exhibit CAJ-RJ-1** to my Rejoinder Testimony which includes the revised H-1 through H-4 Schedules that reflect: (i) minor modifications to Staff's proposed rate design, (ii) an updated revenue requirement that incorporates adjustments addressed in the Rejoinder testimony of other TEP witnesses which includes the $81.5 million increase in revenue requirement settled on by most parties in this proceeding and (iii) revised bill impact calculations. A summary of the bill impacts resulting from the Company's proposed rates can be found in **Exhibit CAJ-RJ-2**.

The Company has generally followed Staff's recommended rate design for all rate classes and, with minor adjustments, has reflected those rates in **Exhibit CAJ-RJ-1**, Schedule H-3. The Company recommends the Commission approve these rates and reject the rates proposed by the other parties to this proceeding.

Q. What has the Company used as its allocation of revenue in the current proposal?

A. Currently, the Company is generally accepting many of Staff's revenue allocations with some adjustments to certain rate classes. The Company still believes less revenue should be allocated to the LPS and 138 kV rate classes. Therefore, its proposal reduces the

Staff's allocation to those rate classes. The Company's final proposal is shown on the revised H-1 and H-2 included in **Exhibit CAJ-RJ-1**.

IV. <u>LFCR.</u>

Q. Staff and AECC continue to oppose the Company's proposed changes to the LFCR mechanism. Would you like to provide an additional response to those concerns?

A. The Company disagrees with Staff's position on changes to the LFCR and respectfully asks Staff to reconsider its position.

AECC's position to eliminate the LFCR is simply unreasonable. Mr. Higgins has provided no factual support for this position and has done nothing to explain why the Commission's conclusion in its Decoupling Docket[1] is wrong. The Commission was very clear in its decision in the Decoupling Docket that the revenue designed to recover fixed costs that are lost as the result of EE and DG programs should be recovered by the utility. As shown in my earlier testimony, the exclusion of lost generation fixed-cost revenues from the current LFCR mechanism does not fully accomplish that objective. The Commission came to an appropriate conclusion in Decoupling Docket and the application of that conclusion is all the Company is asking for in this proceeding. Staff has taken a position in this proceeding that results in much of those fixed costs remaining unrecovered. This is inconsistent with the Commission's decision and the Company believes now is the time to fix that. Although the Commission recently declined to allow the recovery of lost generation fixed-cost revenues in the LFCR for UNS Electric, as discussed below, the fixed costs associated with TEP's generation fleet are much larger on both a relative and absolute basis.

[1] Final ACC Policy Statement regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures. December 29, 2010, Docket Nos. E-00000J-08-0314 and G-00000C-08-0314.

Mr. Higgins' position is even more unreasonable in light of the eleventh hour Option 2 Buy Through proposal. I will discuss this further in the section where I address the Buy Through rate. Mr. Higgins' recommendations relating to the LFCR should be denied.

Q. Why do you believe Staff is wrong as it relates to the LFCR related changes requested by the Company?

A. The most significant item opposed by Staff is the recovery of lost fixed generation costs revenue through the LFCR. Staff continues to, in the Company's opinion, mistakenly believe that by reducing purchased power costs the Company somehow reduces it fixed generation costs – and that simply isn't true. These costs are fixed plant costs that do not vary with consumption. Staff has provided no evidence or substantiated explanation as to how the Company's lost fixed generation costs are addressed other than through increased sales. As mentioned in my Rebuttal Testimony, the Company agreed to incorporate an adjustment to allow for increased retail sales if that is a reason to not allow the Company to recover its lost fixed generation cost revenues.

As set forth in my Rebuttal Testimony, when rates are created, the fixed cost associated with the Company-owned generation facilities and related equipment is included in the costs allocated to the various rate classes. Those costs are then spread over an approved number of billing determinants, either demand or volumetric, depending on the class. Once in the rates, the Company must realize at least that level of billing determinants to have any reasonable opportunity to recover those costs. Without the Company's proposed changes to the LFCR, or significantly higher retail sales levels, the Company is assured of not recovering those fixed costs related to fixed generation – as a result of meeting mandated EE and DG policy objectives. We are simply requesting the Commission fairly apply its policy with respect to revenues lost as a result of EE and DG.

Q. Please estimate the unrecovered revenues caused by these omissions in the LFCR.

A. The table below shows the accumulated historical under-recovery of fixed generation cost revenues resulting from EE and DG programs. The total accumulated lost fixed cost was approximately $66 million over the three year period ending December 31, 2015. Of that amount, the current LFCR mechanism provided for recovery of only $27 million, or approximately 41% of the lost fixed cost revenues. The omission of generation costs and one-half of lost demand revenues therefore resulted in the Company experiencing an estimated $39 million shortfall in fixed-cost revenues. For calendar year 2016, it is estimated that an additional $26 million shortfall will be realized, an amount equal to 32% of the $81.5 million non-fuel revenue deficiency agreed to by TEP and the other settling parties in this case. That shows just how significant these reductions in lost fixed cost revenues are to the Company's ability to earn its authorized return. If the LFCR is not adjusted, the estimated shortfall for calendar year 2017, which assumes a January 1, 2017 effective date for new rates and re-start of LFCR accruals, is nearly $13 million. All of these values and the supporting data have been included in the evidence provided in this proceeding. Consequently, this issue should be addressed and corrected in this rate case.

Table 1: LFCR Impact of Fixed Generation (including Fixed Must Run) and Full Demand

Calendar Year	Total Lost Fixed Cost Revenue	Current LFCR Recovery	Impact of Gen & Full Demand
2013	$11.2M	$4.6M	$6.6M
2014	$22.0M	$9.0M	$13.0M
2015	$33.2M	$13.6M	$19.6M
Total	$66.3M	$27.1M	$39.2M
2016 Estimate	$43.7M	$17.9M	$25.7M
2017 Estimate	$26.1M	$13.1M	$12.9M

	EE			DG		
Calendar Year	Total Lost Fixed Cost Revenue	Current LFCR Recovery	Impact of Gen & Full Demand	Total Lost Fixed Cost Revenue	Current LFCR Recovery	Impact of Gen & Full Demand
2013	$7.4M	$3.1M	$4.3M	$3.7M	$1.5M	$2.2M
2014	$16.4M	$6.8M	$9.6M	$5.6M	$2.2M	$3.4M
2015	$24.1M	$9.9M	$14.2M	$9.1M	$3.6M	$5.5M
Total	$47.9M	$19.8M	$28.1M	$18.4M	$7.3M	$11.1M
2016 Estimate	$30.1M	$12.4M	$17.6M	$13.6M	$5.5M	$8.1M
2017 Estimate	$15.0M	$7.5M	$7.5M	$11.1M	$5.7M	$5.4M

Q. Mr. Solganick also opposes the recovery of any lost fixed costs generated by the "Buy-Through" rate in the LFCR. Is that a concern to the Company?

A. Yes. If the Commission approves any variation of the "Buy-Through" rate that results in a reduced (lost) level of fixed cost recovery (including fixed generation costs), lost fixed costs should be eligible for recovery. The Company would consider other proposals that would allow for the recovery of those lost fixed costs, but the LFCR appears to be the most appropriate mechanism.

Q. Will these changes require a revised POA be submitted once the details of these rate design and LFCR issues are resolved?

A. Yes. The Company has proposed a revised LFCR POA reflecting its proposed changes, but any modification to the Company's original proposal could require further revisions to the POA. As with the other POAs discussed by Staff witness Van Epps, the revised POA could be submitted within 60 days of the final decision in this proceeding.

Q. Mr. Higgins suggests that the LGS customer class be exempted from the LFCR. He supports this statement by stating, "a significant part of TEP's concern regarding LGS customers can be addressed through rate design."[2] Please comment.

A. If more of the fixed costs were included in fixed rate components his statement could be correct. However, that is not the case for this rate class. Currently LGS customers benefit from EE and DG programs, and TEP recovers a large portion of the fixed costs to serve them through volumetric rates. Therefore, this class should participate in the LFCR and contribute to lost fixed cost recovery. Mr. Higgins' suggestion that LGS customers be excluded from the LFCR should be rejected.

Q. Does Mr. Higgins mischaracterize how the shifting of costs occurs in the LFCR?

A. Yes. The LFCR currently excludes lost fixed costs for a few rate classes, an agreement that arose out of settlement. However, just because these lost fixed costs are excluded from the LFCR, doesn't mean that there isn't a cost shift, which I explained earlier. So Mr. Higgins is incorrect in stating that a cost shift would not occur with the exclusion of the LGS class from the LFCR.

[2] Higgins Surrebuttal 40:1.

V. BUY-THROUGH PROPOSALS.

Q. You have already expressed that the Company does not support any form of the Buy-Through mechanism. Does AECC witness Higgins' Option 2 proposal relieve any of those concerns?

A. No. In fact, having only a couple of days to review the proposal, it appears to have the same major flaws as the Option 1 variation. The Company's fixed generation costs do not go away after 5 years. Most of those facilities have a useful life of far more than 5 years and are included in base rates with the understanding that they will be recovered over that useful life. Mr. Higgins' proposals leave all of those costs to the other customers after 5-years. This is just another way of shifting costs to the remaining customers for plant that was placed in service to meet his client's needs. Without addressing any other issues that the proposal may have, at the very least the full unbundled generation cost should be recovered from participating customers long past the 5 years being proposed by Mr. Higgins. This amount could be adjusted to allow for increased sales if they actually occur, much in the same way the fixed generation costs could be adjusted for increased retail sales in the LFCR if deemed appropriate.

Additionally, the Company's review of this Option 2 proposal, which is based on a program in place for Portland General Electric ("PGE"), has identified other concerns. In the brief time I have had to arrive at a cursory understanding of what PGE has in place, I found that they have a partial decoupler as well. While this decoupler actually includes *the full recovery of fixed generation costs*, which supports the Company's LFCR related proposal, I do not believe the combination of this Option 2 Buy Through rate and a revised decoupler would be in the best interest of the customers who are unable to take advantage of the program. Staff's witness Solganick[3] does an excellent job of explaining

[3] Solganick Surrebuttal 21:9 through 22:9.

why a Buy Through proposal will likely result in all remaining customers incurring additional costs if the proposals are allowed. Moreover, I located testimony submitted by PGE in Oregon Public Utility Commission Docket No. UE 236, PGE's Multi Year Opt-Out Window that confirms that concern. On page 6, lines 18-22, of Mr. Marc Cody's Direct Testimony, he states that nearly $7 million of purchased power costs were shifted to non-participants, including residential customers, in a single year of the program. That fact, when combined with the lack of time to thoroughly analyze the details of the proposal are enough for the Company to recommend it be rejected. This cost shift would also be likely to occur in the Franchise proposal made by Freeport.

One additional fact stood out as I quickly reviewed PGE's rates. The generation costs reflected in PGE's tariffs appear to be substantially higher than TEP's generation costs. In fact, in the rate schedules I reviewed they appear to be over $0.06 per kWh, which is as high as or higher than the full retail rate TEP has proposed for the 138 kV rate. This leads me to wonder what Mr. Higgins was thinking when he referred to "...TEP's high-priced service territory..." in his testimony.[4] Currently the Company is proposing an approximate $0.0626 per kWh average rate for the 138 kV rate class.

In summary, all versions of the Buy-Through rate should be rejected as proposed.

If a Buy Through option is approved, I believe the last line of the referenced section of Mr. Solganick's testimony on this issue summarizes it best: "In essence, this is a heads we win, and a tails you lose scenario." To allow the proposed aggregation of customers suggested by AECC, Kroger and Wal-Mart would exacerbate this issue, assuming a reasonable definition of who would qualify to aggregate could be created as discussed by Staff witness Solganick.[5]

[4] Higgins Surrebuttal 10:19.
[5] Solganick Surrebuttal 24:15-18

VI. DEMAND CHARGES AND RATCHETS.

Q. How would you characterize the assertion that demand ratchets on the MGS, LGS, and LPS classes are not in the best interest of the Company's customers?

A. A few Intervenors (interestingly not utility customers) claim that demand ratchets mismatch costs and revenues, however, the reality is exactly the opposite. Ignoring the trivial case of a non-existent customer, the cheapest customer for the Company to serve would be a customer with a 100% load factor when considering the capacity burden placed on the system. That is, a customer who uses exactly the same kW every hour of the year. The generation, transmission, and distribution systems can be sized to exactly match this customer's load. Further, the assets are fully utilized meaning the costs associated with such equipment can be collected over reduced charges. Suppose, however, this same customer were to suddenly use the same amount of kW (capacity) but only for 1-hour of the year. The generation, transmission, and distribution systems must still be of the same size to accommodate that 1-hour load and thus the cost to serve such a customer is identical as the hypothetical 100% load factor customer. The assets in the 1-hour case are barely used over the year and therefore the costs must be recovered over very high charges (either kW or kWh). In the case where both these types of customers are on the same rate schedule without a ratchet, the 100% load factor customer would be greatly subsidizing the 1-hour customer. However, by adding a 100% demand ratchet both customers would be paying equal amounts for the generation, transmission, and distribution systems without subsidy because all components must be sized the same with the same resulting cost to serve (energy is recovered volumetrically and tracks usage dollar for dollar). By lowering the demand ratchet to 75%, the 100% load factor customer is subsidizing the 1-hour customer but to a far smaller amount compared with no ratchet. The table below illustrates these points on two real customers.

Table 2: Examples Impact of Various Ratcheted Demand Applications;

kW Billing Determinants	Low Load Factor No Ratchet	75% Ratcheted	100% Ratchet	High Load Factor No Ratchet	75% Ratcheted	100% Ratchet
7/1/2014	576	576	576	590	590	595
8/1/2014	591	591	591	594	594	595
9/1/2014	554	554	591	580	580	594
10/1/2014	537	537	591	584	584	594
11/1/2014	381	443	591	584	584	594
12/1/2014	346	443	591	574	574	594
1/1/2015	230	443	591	568	568	594
2/1/2015	215	443	591	568	568	594
3/1/2015	195	443	591	568	568	594
4/1/2015	356	443	591	560	560	594
5/1/2015	322	443	591	576	576	594
6/1/2015	506	506	591	576	576	594
Billing Determinants	4,810	5,867	7,079	6,922	6,922	7,129
$/kW	$19.132	$17.550	$15.797	$19.132	$17.550	$15.797
Customer kW Charge	$92,024	$102,973	$111,832	$132,430	$121,481	$112,622

	Nominal	75% Ratcheted	100% Ratchet
Total kW Charge	$224,454	$224,454	$224,454

First notice, in total, the revenue collected in kW charges ($224,454 annually) is revenue neutral among the cases because the kW component in all cases is collecting the cost associated with the service of these two customers. Next notice that the 100% ratchet case collects nearly the same amount of revenue from both customers; the cost to serve the kW (capacity) load of these customers is nearly identical because they both have nearly the same peak kW. Next notice that the case without a ratchet results in a subsidy of $19,808 ($132,430 - $112,622 = $19,808 versus $92,024 - $111,832 = -$19,808) being paid from the high load factor customer to the low load factor customer. The 75% ratchet the Company is proposing mitigates this subsidy to $8,859. This example clearly shows ratchets do not cause intra-class subsidies and cost shifts rather they actually help to mitigate them. For this reason, the Company's proposal to use demand ratchets is in the best interests of our customers.

Additionally, it should be noted that many of the LGS and LPS customers are intervenors in this case. None of these parties have filed testimony arguing for the removal of demand ratchets on which they are already being billed, likely because these intervening parties are higher load factor customers who benefit from the ratchet. If the ratchet mechanism is unduly punitive to the affected customers, then why are they not advocating for higher demand charges and a reduction in the ratchet?

I find it equally interesting that the only parties advocating for the reduction or elimination of ratchets are solar advocates including SOLON and EFCA. The elimination of ratchets increases the economic opportunity for their business model to profit at the expense of our most efficient customers. However, ratchets do not stifle solar. Even with the current ratchets, many of the Company's LGS and LPS customers have found a way to benefit from solar systems under the existing demand and ratchet rate design. In the last two years the LGS customers with solar systems have increased from 5.4% to 7.1% of the class and the LPS customers in that same time period, have increased from 11.1% of the class to 26.3% of the class being net metering customers.

Finally, demand charges and ratchet mechanisms are a standard form of rate design for large customers all over the United States and all over the State of Arizona. To state otherwise (as the solar advocates have) is obviously self-serving and in no way the correct direction to move forward as we modernize rates and rate design. The demand ratchet brings the cost to serve closer to cost causation, with the end result rewarding customers that use the system more efficiently and cost effectively, consistent with the Company's cost-based rate design goals.

VII. BASIC SERVICE CHARGES AND REDUCED TIERS.

Q. Please comment on Mr. Baatz's testimony[6] that "There are very few industries that recover fixed costs of operation in an upfront fee prior to even using service. The only examples (Costco, Sam's Club) allow customers to pay an upfront fee for lower cost goods."

A. There are very few industries that adhere to cost-based regulation. Mr. Baatz cites a few businesses, none of which are subject to the same regulatory oversight as TEP's rates are. None of these companies use embedded cost theory to set prices and none of them require a 12-18 month legal proceeding to establish cost based rates. Cost-based regulation is based on the theory that the fairest way to allocate revenue recovery to the utility's customers is to assign them as nearly as possible to those who cause the costs. And as Dr. Overcast shows in his testimony, there is ample evidence as to why the minimum system approach is a cost-based approach to calculating the basic service charge.

Q. What is your opinion on Mr. Baatz's take on Bonbright?

A. In the Company's opinion, Mr. Baatz once again misapplies Bonbright's principle of gradualism to best serve a point he is trying to make that has no correlation to what a customer is truly most concerned with: their total bill. The Company views gradualism based on final overall bill impacts rather than percentage changes to individual components of the bill. When the total bill is considered, the bill impacts on a percentage basis are significantly lower, a point that Mr. Baatz conveniently avoids mentioning.

[6] Baatz Surrebuttal 6:19-21.

Q. Please comment on Mr. Huber's assertion that Mr. Jones' misinterpreted RUCO's table from page 26 of Mr. Huber's Direct testimony.

A. RUCO agrees with the Company's statement that "customers are primarily concerned about overall bill reductions."[7] However, RUCO then follows by saying the "very purpose of this table was to illustrate the impact that changes to consumption would have on customer bills. In this context, it is the marginal rate that is most relevant for each group of customers, not the average rate."[8] In my 30 plus years of speaking with customers, I can't ever remember someone saying to me, "What were you thinking when you changed my rates? The marginal rate has changed again!" Any time I have been fortunate enough to be able to speak with a customer, the question always revolves around their total bill.

Again, the Company's comments are still valid as the table presented in Mr. Huber's testimony does not include fuel charges which are incurred on a per-kWh basis like the per-kWh energy charges are, and they are certainly an important part of the customer's bill. Additionally, Mr. Huber makes an even more fundamental error in assuming that the response to the inclining energy tiers is a marginal one. This is not the case because customers would not typically know when they are moving to the next higher tier rate. Customers know that when they use more their bill gets bigger and that rule of thumb has not been changed, nor has it been reduced. For those customers trying to conserve (or save money) there is still plenty of incentive to use less.

Q. Please comment on Mr. Huber's and Mr. Baatz's claims that the proposed Company rates disincentivize energy conservation.

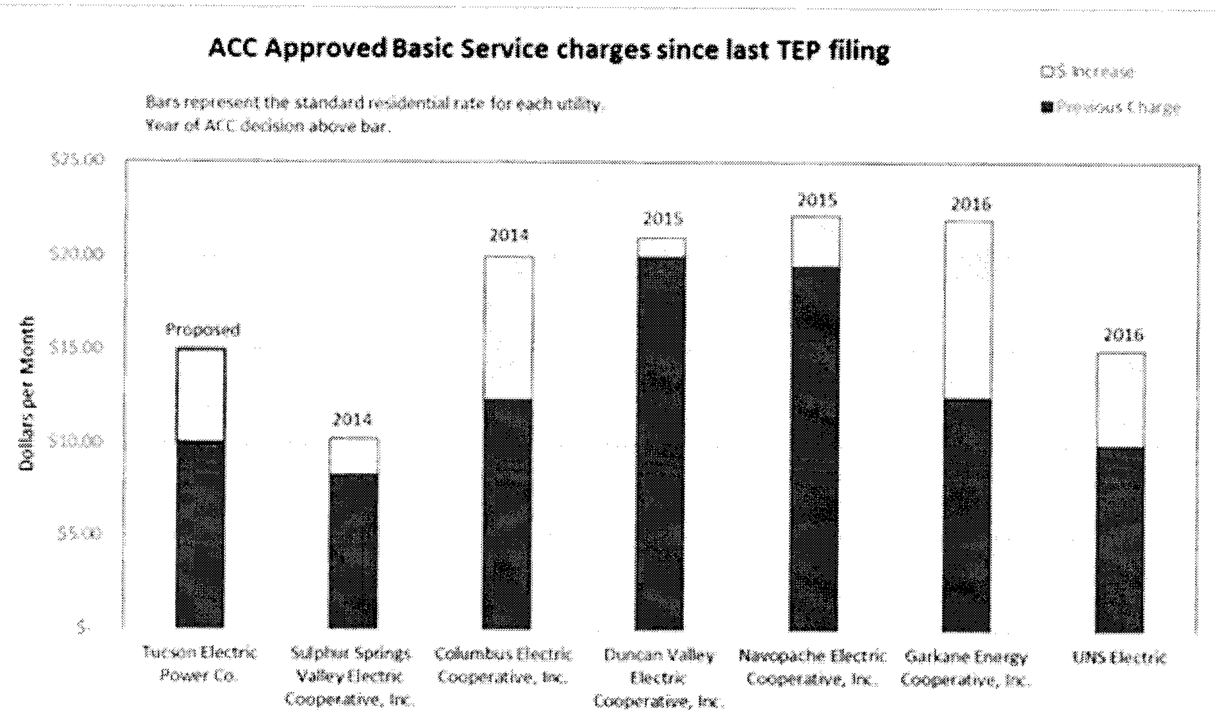
A. Mr. Huber and Mr. Baatz draw their conservation conclusions by comparing the proposed rates to a hypothetical set of rates, whereas the Company's conclusions are based off of

[7] Huber Surrebuttal 41:9
[8] Huber Surrebuttal 41:10-13

the correct comparison which is the current rates to the proposed rates. The idea that the Company is disincentivizing customers from conserving energy is just not true. The fact is that there is as great an incentive to save under the Company's Rejoinder position, as there was for its Rebuttal and Direct positions. It is disheartening to see multiple Intervenors obfuscate this by presenting misleading comparisons.

Q. Mr. Huber cites the current policy of line extensions as an example where a customer-related fixed cost was not recovered through a corresponding fixed charge for "subjective policy reasons". Please comment.

A. The Commission has recognized the need to recover fixed costs through fixed charges through the basic service charge and has done so in every single rate case since the Company's last proposal. In multiple instances, the basic service charge has increased at a greater percentage than what the Company is currently proposing.



RUCO highlights the root issue of rate design in that the Company is currently unable to charge each and every individual customer their embedded cost to serve. The Company does not dispute the notion that the cost to serve varies between seasonal, vacant, rural and urban customers. The Company has maintained all along that there are intra-class subsidies embedded in rate design and its goal is to reduce them where possible. The end result from RUCO's and other Intervenors' opposition to cost-based rates is not only the continuance of but rather the growth of intra-class subsidies. The time is right for modifying and modernizing rates and rate design in a manner that will start to remedy those subsidies where possible.

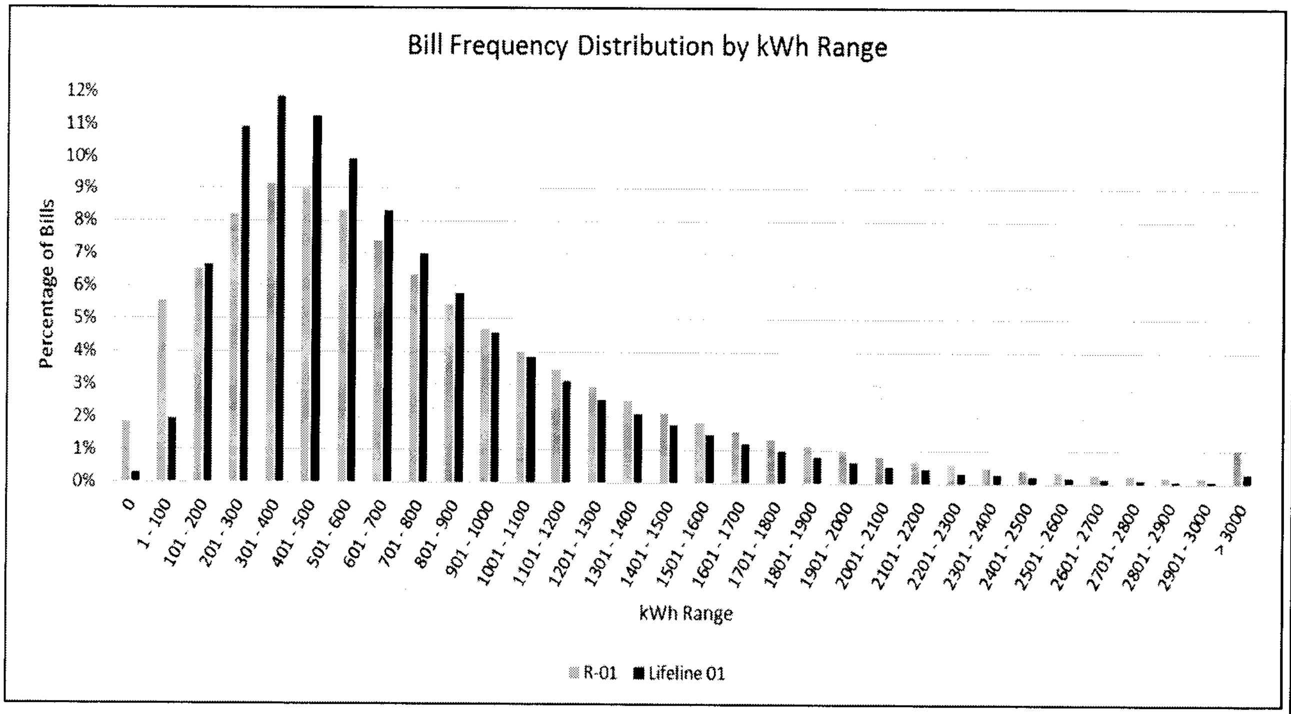
VIII. MISCELLANEOUS ISSUES.

A. Lifeline Rates and Discounts.

Q. In your introduction you mentioned you would like to discuss a few issues you identified in the Surrebuttal testimony of certain witnesses. What are the issues you would like to address relating to the Company's proposed Lifeline rates?

A. There still seems to be a misunderstanding of how our Lifeline customers use electricity. Some references were made to there being a higher number of low-use customers in the low-income category of customers. In reality, this customer group uses energy in a manner very similar to the majority of our standard residential customers. Please see the chart below showing the distribution of usage by bill for both R-01 customers (in grey on the left side of each pair of columns) and similar Lifeline customers (in black on the right side of each pair of columns). You will notice the distribution of bills mirrors the R-01 class as a percentage of total bills throughout the various usage ranges. The Company is proposing to provide a flat discount to all Lifeline customers. This proposal allows those customers who use more than 500 kWh in a billing month to benefit from lower kWh rates for higher usage amounts and for customers with lower usage amounts to benefit from a flat discount of between \$15 and \$41 each month. This discount more than offsets the increase in the basic service charge and helps reduce the per kWh rate paid in this lower usage tier. Mr. Baatz[9] tries to misdirect the issue by focusing on only the change in basic service charge. Again, he conveniently omits the actual bill impacts and the \$15 - \$41 credit these customers will receive when doing his analysis.

As final rates are developed at the conclusion of this proceeding, those flat discounts can be adjusted to mitigate the level of impact these customers would experience. Any increase in rates would be added to the funding amount included in the Company's current revenue allocation proposal. Under our current proposal the Lifeline customers are receiving approximately \$2.8 million in discounts.



[9] Baatz Surrebuttal 8:25.

Q. ACAA witness Ms. Zwick[10] suggested the use of a tiered discount for the Lifeline customer. What are your thoughts on this suggestion?

A. The Company appreciates Ms. Zwick's proposal and believes the underlying goal has merit, however the Company is of the opinion that its proposal is more beneficial to the Lifeline customers. The most important change for the Company is to move all customers to the standard tariff rate design. If all customers are on the same rate design, the Company could consider other options that will not add complexity to the billing process, but starting with the proposed credit for the lowest income customers and phasing it down as the income increases may not be as beneficial for the customer as the Company's proposal. Additionally, it will be difficult to verify specific income levels and how long the customer is actually at that level. It would add complexity, and uncertainty, therefore the Company still believes its option is the best for most Lifeline customers. The Company is willing to consider modifications to those discounts once final rates are created, but requests that the total anticipated funding level be accounted for in the final rates if that change is made.

B. Master Metered Mobile Home Parks.

Q. AECC witness Mr. Higgins has requested the frozen Master Metered Mobile Home Park ("MMMHP") rate be expanded to include all existing MMMHPs regardless of what rate they are currently being served under. You have objected to this in your earlier testimony. Do you have anything you would like to add?

A. Yes. While most of my objections have been provided in earlier testimony I believe it is important to mention that these customers chose the rate they were on and felt it was the most appropriate at the time. The MMMHP has been frozen for over 15 years. It was

[10] Zwick Surrebuttal 14:12.

frozen as a result of a Commission Order. The Company does not believe it is appropriate to un-freeze the rate.

Q. Mr. Higgins says the Company denied him access to information on LGS mobile home parks and therefore it is interesting the Company provided numbers using four mobile home park customers. How does the Company respond?

A. The Company objects to the implication that the Company denied Mr. Higgins information. In the data request, Mr. Higgins asked the Company for an estimate of the total number of mobile home park customers not served under the GS-11F rate. The Company does not have a simple way of identifying the number of mobile home parks not on the GS-11F rate. The Company did a search of customer's on the LGS13 rate whose name in the Company's database contained the word "MOBILE" or "RV PARK" to get a sense of how these customers performed on a cents/kWh basis. The Company in no way claimed that this list is exhaustive or provided an estimate for the number of MMMHP's in its service territory.

Q. Mr. Higgins objects to the Company's stance that the customers of MMMHP's are not customers of the Company in regards to a pass through of Lifeline discounts. How does the Company respond?

A. The Company's primary objection to the Lifeline discount to customers in a MMMHP is that the Company can't verify the discount is actually being passed through to the qualifying residents.

Q. Mr. Higgins' argues that Arizona Revised Statute 33-1413.01 requires that MMMHPs must not charge their residents more than the utility's prevailing rates for basic single family residential service.[11] Do you believe it is appropriate to charge the MMMHP a non-residential rate?

A. Yes. The referenced statute is a provision that allows for a limited situation where the utility's customer may essentially "resell" its product without the customer being a regulated utility. The MMMHP is a non-residential general service customer and should be on the general service rate they would normally be served on under current rates. The MMMHP has an opportunity to recoup a portion of its utility bill by "reselling" a portion of the energy they purchase. The referenced statute is designed to prevent them from profiting on this "resale". The statute in no way guarantees them full recovery of their utility bill. MMMHP's are not residential customers. They are general service customers. They should pay general service based rates. They are fortunate they have been allowed to remain on a frozen, subsidized rate. Any balance over what they are able to recoup from their tenants is a cost of doing business. They are free to recoup that portion through the rent they charge their tenants. The Company therefore recommends the Commission reject AECC's proposal.

C. <u>Class Cost of Service Study.</u>

Q. Does the Company believe its proposed CCOSS is correct or should additional changes be made as suggested by Mr. Higgins?[12]

A. The Company has made the corrections to the CCOSS it believes are necessary. The remaining changes recommended by Mr. Higgins are not appropriate in the Company's opinion. Company witness Dr. Overcast will provide a brief explanation as to why the Company's use of an average load factor is appropriate.

[11] Higgins Surrebuttal 34:10-12
[12] Higgins Surrebuttal 24:4

D. <u>RCS Rate.</u>

Q. Staff witness Mr. Gray has recommended a rate for the Residential Community Solar ("RCS") program the Company proposed in its most recent REST filing. Do you wish to address his proposal?

A. Yes. Once the final rates are determined in this proceeding a new RCS rate should be calculated based on the cost to serve a like situated residential customer. Mr. Gray's recommendation is premature if the Commission agrees that a special rate should be created. If that is the final decision then a final rate should be determined when Phase 2 of this case is finalized. Phase 2 will be addressing most of the net metering related issues.

E. <u>Solar Meter Charge.</u>

Q. With most of the net metering issues being delayed to Phase 2, does the Company wish to propose an additional charge for the incremental meter cost necessary to provide solar partial requirements service?

A. Yes. The Commission believed it was appropriate to establish an incremental meter charge in the Open Meeting addressing the Company's sister company, UNS Electric's rate case. The Company believes it is appropriate to do so now in this proceeding as well. The Company has reviewed the UNS Electric decision and the evidence in this proceeding and agrees with RUCO witness Mr. Huber's general method of calculating the correct level of incremental charge[13] that should be assessed to all new net metering customers subsequent to the rate effective date granted in this proceeding. The Company also agrees with Mr. Huber that his proposed charge is too conservative.

[13] Huber Surrebuttal 13:3-18.

In the UNS Electric Open Meeting, an embedded cost estimate of meter costs was used. This understates what the incremental meter costs should be by a substantial amount. First, the number out of the CCOSS is an average of all meters in service regardless of how close they are to being fully depreciated. This charge is for new customers and new installations, therefore the marginal cost data presented by the Company in my Direct Testimony as **Exhibit CAJ-1** is the appropriate source for this information. Schedule 1 lines 5 (Meters), 13 (Meter Reading Expense), 14 (Customer Records & Collections), 18 (Informational and Instructional Advertising Exp.), 19 (Misc. Customer Service & Information Exp.) and 20 (Customer A&G costs) represent the costs that should be recovered from the new net metering customers. The sum of these entries divided by 12 result in a charge of $8.62 per month. All of the specified costs are calculated on an average meter basis and are specific services that are provided to the net metering customer. This is the charge the Company believes should be applied incrementally to all new residential net metering installations as of the rate effective date of this order. This same calculation produces a charge of $9.13 per month for new SGS net metering customers.

Since these are new customers with new meters, the marginal cost study is the most appropriate data to use in the calculation. Mr. Huber's conservative charge of $6 would understate the actual cost associated with the incremental addition of the net metering meter and related equipment. Additionally, since the marginal cost study is based on standard meter installations, this estimate does not include the incremental cost of the bi-directional meter that would be needed to serve the solar partial requirements customer. The marginal cost study is based on a standard meter, not the more expensive bi-directional meter. Therefore even the numbers proposed above can be considered conservative.

F. Wal-Mart Revenue Support Rider.

Q. Did you have any additional comments on Wal-Mart's proposed Revenue Support Rider ("RSR") you wish to add to your Rebuttal Testimony?

A. The Company does support minimizing inter-class subsidies and, if created correctly, could see a variation of the proposal being considered. The Company shares many of the concerns expressed by Staff witness Mr. Solganick[14] and agrees with his suggestion that a detailed debate would be appropriate before moving forward with the proposal.

G. DSM and ECA Charge.

Q. What is the Company's position as it relates to Staff witness Mr. Van Epps recommendation that the DSM charge and the ECA be based on a per kWh rate instead of a percentage rate?

A. The Company is still of the opinion that the correct approach of using a percentage based rate is more equitable for the larger customers and increases the contribution made by DG customers who might otherwise avoid all DSM and ECA charges if charged on a kWh basis.

[14] Solganick Surrebuttal 25:1-15.

H. SGS Cap Wording.

Q. Staff witness Mr. Solganick mentioned in his Surrebuttal Testimony that the language I referenced in my Rebuttal Testimony relating to the movement of an SGS customer to an MGS class if the customer's consumption meets or exceeds 24,000 kWh in consecutive months." Is this the language you intended to be included in all SGS tariffs?

A. No. While I appreciate Mr. Solganick's support and the reason for the support, I made that statement in reference to how we would transfer SGS customers to MGS at the end of a transition period. It was not my intent to change the tariff language originally proposed by the Company in its Direct filing. I believe Mr. Solganick inadvertently assumed my reference to how customers would be migrated to MGS was a modification to the specified section of 2-part SGS tariffs which would have made it sound like the Company intended to modify its proposed tariff language.

My Rebuttal Testimony,[15] in reference to the transition plan, stated:

> SGS customers with usage meeting or exceeding 24,000 kWh in consecutive months will automatically be moved to the MGS rate on the first billing cycle after the rate effective date.

The filed SGS tariffs contained the provision worded as follows:

> If a customer's two month accumulated consumption in the current billing month and the month proceeding meets or exceeds 24,000 kWh, the customer will be moved to the Medium General Service tariff.

[15] Jones Rebuttal 17:4-6.

The Company believes the language originally proposed will still allow an SGS customer two months to accumulate to the total consumption of 24,000 kWh or more which allows them to avoid an immediate move to the MGS rate if a single month's usage exceeds 12,000 kWh. The Company believes this language still meets Mr. Solganick's expressed desire to "not penalize a customer for a single usage excursion".[16]

I. Prepay Rate.

Q. Would you like to respond to Staff witness Connolly's recommendations relating to the Prepay rate?

A. The Company's witness Ms. Smith will respond to most of the recommendations made by Mr. Connolly, but there are a couple of items I would like to address.

The Company is willing to include a Lifeline provision in the Prepay rate. This will be based on the final Lifeline rate approved by the Commission. If the Commission approves the Company's proposal it will be as simple as dividing the standard $15 Lifeline credit by thirty (30) days and providing a $0.50 per day credit to the calculation. The rates will be the same as a standard residential customers and this method will provide a potential Lifeline customer with the same level of discount they would otherwise enjoy.

Q. Please address Staff's witness Mr. Connolly's concern that "TEP is unable to determine when, in the daily billing cycle, a Prepay customer would move from one energy tier to the next".[17]

A. Current residential rates are designed around a monthly billing cycle such that at some point in the month customers who consume above 500 kWh will escalate to a higher tier energy rate. In contrast, Prepay is a pay-as-you go option automated as a daily billing

[16] Solganick Surrebuttal 13:19.
[17] Connolly Surrebuttal 2:13.

cycle that creates a customer alternative to tracking energy consumption on a monthly cycle with sensitivity to the possibility the rate may change later in the month based on the total monthly consumption. The issue is not whether TEP can create a parallel monthly billing model to determine when a customer would have moved from one tier to the next, the issue is that Prepay creates an entirely different option for customers via a singular volumetric rate, equivalent to the weighted average of other RES customers, for the pre-purchase of energy, with no post consumption billing cycle.

As part of is discussion on this topic, Mr. Connolly recommends changing the rate used to calculate the daily Prepay bill.[18] The Company agrees to change the tier breakpoint from 20 kWh per day to 16 kWh per day. This will approximate the 500 kWh monthly breakpoint. The same rate that will apply to the first 500 kWh consumed by a standard residential customer will apply to the first 16 kWh consumed each day by a Prepay customer. Daily consumption in excess of 16 kWh will be charged at the same rate as a standard residential customer pays for consumption in excess of 500 kWh in a billing month.

J. <u>Grandfathering Net-Metered SGS Customers.</u>

Q. How do you characterize the assertion that SGS customers who are also on the net-metering rider have to be grandfathered on their tariff and not just their rider?

A. This is an interesting argument coming from solar interests such as EFCA, Vote Solar, and SOLON for a number of reasons. Most pertinent is that it is contradictory to their own arguments that DG customers must not be treated as a separate class of customers. The Company's current proposal, for purposes of the migration rules, are designed to promote the treatment of all general service customers equally and to not create a

[18] Connolly Surrebuttal 2:23.

separate class or treatment for DG customers thereby allowing the DG customers to continue to reap the benefits of their net metering rider. All customers will be placed in the class that their usage would otherwise qualify them for. Creating additional subsidized customers is not in the public interest and should be avoided if possible.

K. Rate Class Parameters.

Q. Many of the solar advocates claim the Company's proposed minimum and maximum usage or kW limits for each specific rate class are unprecedented and lead to cost inequities. Do you agree with these statements?

A. No. These arguments are categorically false. The truth is, what the Company is proposing is very common and seeks to end cost mismatches. First, moving customers to rates based on size occurs at all of the electric utilities in Arizona with the exception of one. APS, SRP, UNS Electric, TRICO Electric Cooperative, Sulfur Spring Valley Electric Cooperative, Navopache Electric Cooperative, Dixie Escalante Rural Electric Association, Duncan Valley Electric Cooperative, Inc., Garkane Energy Cooperative, Inc., Graham County Electric Cooperative, Inc., Mohave Electric Cooperative, Inc., and Morenci Water and Electric Company all have size differentiated tariffs which move customers to their appropriately sized tariff with TEP being the one exception to this rule. Additionally, no other electric utility in Arizona allows net metering customers to stay on their smallest tariff regardless of their actual size and character of service. TEP is currently the outlier in this regard and the Company's proposals are seeking to move towards a sound rate design theory, not maintain what is clearly an outdated and problematic practice. Second, the proposal to move customers to like sized rates seeks to help mitigate cost mismatches that are currently occurring. By moving customers to like sized rates, those customers with higher load factors will save on their utility bills reflecting their lower average cost of service when compared to low load factor customers.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit CAJ-RJ-1

Tucson Electric Power Company
Summary of Revenues by Customer Class
Present and Proposed Revenues
Test Year Ended June 30, 2015

Line No.	Rate Description	Test Year Net Revenue	Net Increase	Proposed % Increase to Test Year	Adjusted Test Year Revenue	Proposed Dollar Increase	Proposed % Increase to Adjusted Test Year	Proposed Net Revenue
1	**Class Summary**	$	$	%	$	$	%	$
2	Residential	414,763,081	35,885,492	8.7%	398,768,236	51,880,337	13.0%	450,648,572.91
	General Service	263,662,971	(20,752,230)	-7.9%	246,857,775	(3,947,034)	-1.6%	242,910,741.37
	Large General Service	112,713,124	32,422,031	28.8%	117,340,158	27,794,996	23.7%	145,135,154.18
4	Large Power Service	98,073,783	(1,846,266)	-1.9%	91,982,834	4,244,682	4.6%	96,227,516.85
5	Transmission Service 138kV	37,946,796	(6,884,163)	n/a	30,447,958	614,675	2.0%	31,062,633.08
6	Lighting	4,772,245	751,878	15.8%	4,611,607	912,515	19.8%	5,524,122.56
7	Subtotal	931,931,999	39,576,741	4.2%	890,008,569	81,500,172	9.2%	971,508,741
8	**Other Operating Revenue**	$31,727,877		N/A	$31,727,877	N/A	N/A	$31,727,877
9	**Total**	**$963,659,876**	**$39,576,741**	**4.1%**	**$921,736,446**	**$81,500,172**	**8.8%**	**$1,003,236,618**
						$81,500,000		
						172		

Supporting Schedules
H-2-2

Recap Schedules
A-1

Links
Other Operating Revenues - Revenue Requirement Model

Note:
-1 Test Year Billed Margin Revenues calculated $50,952 more than Booked Revenues.
-2 Test Year Billed Fuel and PPFAC revenues calculated $28,842 less than Booked Revenues.
-3 Total increase is $22,110 more than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
Class Summary										
Residential	4,618,963	3,675,966,286	796	(24,845,354)	4,624,515	3,651,120,932	790	4,624,515	3,651,120,932	790
General Service	461,846	2,133,735,714	4,620	(1,402,844)	462,775	2,132,332,869	4,608	460,923	1,840,615,447	3,993
Large General Service	7,013	1,189,053,400	169,550	(11,891,293)	6,931	1,177,162,108	169,835	8,783	1,468,879,529	167,237
Large Power Service	192	1,386,000,646	7,218,753	138,916,658	204	1,524,917,303	7,475,085	204	1,386,220,602	6,795,199
Transmission Service 138kV	12	635,151,223	0	(138,696,701)	12	496,234,565	0	12	496,234,565	41,352,880
Lighting	207,259	38,938,160	188	1,936	207,267	38,940,096	188	207,267	38,940,096	188
TOTAL COMPANY	5,295,285	9,058,845,428	1,711	(37,917,597)	5,301,705	9,020,707,874	1,701	5,301,705	8,882,011,173	1,675
								(0)		
Residential Schedules										
TE-R-01	4,179,070	3,280,964,594	785	(17,027,762)	4,184,314	3,263,936,831	780	4,184,314	3,263,936,831	780
TE-201A	138,080	130,588,706	946	(992,712)	138,058	129,595,994	939	138,058	129,595,994	939
TE-201B	7,903	8,666,134	1,097	(270,031)	7,755	8,396,104	1,083	7,755	8,396,104	1,083
TE-R80	98,375	110,682,540	1,125	(2,373,544)	96,994	108,308,996	1,117	96,994	108,308,996	1,117
TE-R8	754	579,737	769	643,017	1,368	1,222,754	894	1,368	1,222,754	894
TE-R01BC	13,711	11,172,024	815	231,296	14,020	11,403,320	813	14,020	11,403,320	813
Lifeline Rate Schedules										
TE4-01	6,104	3,418,618	560	(222,520)	5,794	3,196,098	552	5,794	3,196,098	552
TE4-21	36	34,185	950	(779)	36	33,406	928	36	33,406	928
TE4-70	72	59,862	831	(941)	72	58,921	818	72	58,921	818
TE5-01	14,084	9,286,821	659	(372,346)	13,698	8,914,475	651	13,698	8,914,475	651
TE5-21	22	25,179	1,145	(10,460)	13	14,719	1,132	13	14,719	1,132
TE5-70	138	94,379	684	(4,851)	134	89,528	669	134	89,528	669
TE6-01	84,662	61,762,560	730	(8,710,908)	74,767	53,051,652	710	74,767	53,051,652	710
TE6-21	228	262,501	1,151	(31,382)	208	231,119	1,112	208	231,119	1,112
TE6-70	839	782,644	933	(170,654)	683	611,990	896	683	611,990	896
TE6-201A	3,756	3,376,855	899	(386,675)	3,397	2,990,181	880	3,397	2,990,181	880
TE6-201B	63	46,930	745	(4,083)	60	42,848	714	60	42,848	714
TE8-01	8,307	8,093,719	974	(1,148,089)	7,336	6,945,630	947	7,336	6,945,630	947
TE8-21	84	124,764	1,485	(1,279)	84	123,485	1,470	84	123,485	1,470
TE8-70	225	223,584	994	(21,111)	211	202,473	958	211	202,473	958
TE8-201A	137	189,352	1,382	(39,071)	112	150,281	1,346	112	150,281	1,346
TE6-01BC	223	159,842	717	(22,220)	196	137,622	701	196	137,622	701
TE-R-01LL	59,739	39,538,976	662	9,350,601	72,257	48,889,577	677	72,257	48,889,577	677
TE-R01LB	149	123,563	829	15,799	166	139,362	838	166	139,362	838
TE-201AL	1,399	1,205,658	862	457,541	1,884	1,663,199	883	1,884	1,663,199	883
TE-201BL	20	27,399	1,370	30,026	40	57,425	1,454	40	57,425	1,454
TE-R80LL	767	625,652	816	76,511	846	702,163	830	846	702,163	830
TE-R8LL	16	11,669	729	(890)	13	10,779	808	13	10,779	808
Residential Unbilled		3,837,839								

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
General Service										
TE-GS10	426,132	1,700,811,779	3,991	10,550,412	427,562	1,711,362,191	4,003	384,015	602,159,416	1,568
TE-GS11	3,580	48,768,661	13,623	(2,197,623)	3,451	46,571,038	13,495	3,451	46,571,038	13,495
TE-GS76	14,274	175,721,877	12,311	(2,109,763)	14,046	173,612,114	12,360	8,917	30,031,910	3,368
TE-G10BC	383	4,734,474	12,362	76,198	389	4,810,672	12,361	305	515,997	1,692
TE-GSM10	9,837	67,460,308	6,858	(827,799)	9,723	66,632,509	6,853	8,047	22,547,155	2,802
TE-G10MBC	526	27,240,424	51,788	(112,154)	524	27,128,270	51,785	0	0	0
TE-GS43	7,114	102,037,299	14,343	178,775	7,081	102,216,075	14,436	7,081	102,216,075	14,436
TE-MGS				0				43,502	890,563,735	
TE-MGSTOU				0				5,160	130,716,715	
TE-MGSBC								446	15,293,406	
General Service Unbilled		6,960,891								
Large General Service										
TE-LGS13	5,312	859,436,643	161,792	(4,638,491)	5,279	854,798,152	161,915	6,999	1,117,522,546	159,658
TE-LG85	1,606	310,229,617	193,169	(9,593,839)	1,556	300,635,778	193,249	1,525	313,499,267	205,594
TE-L13BC	95	21,576,660	227,123	151,518	96	21,728,178	225,812	259	37,857,717	146,221
Large General Service Unbilled		(2,189,520)								
Large Power Service										
TE-LLP14	26	139,880,570	5,380,022	(5,790,325)	24	134,090,245	5,587,094	0	0	0
Special	0	28,794,874	2,399,573	(28,794,874)	0	0	0	0	0	0
Large Power Service TOU	166	1,219,237,682	7,344,805	171,589,377	180	1,390,827,059	7,726,817	204	1,386,220,602	6,795,199
Large Power Service Unbilled		(1,912,480)								
Transmission Service 138kV										
TE-T138kV	12	635,151,223	52,929,269	N/A	12	496,234,565	41,352,880	12	496,234,565	41,352,880
Lighting										
TE-P41	9,104	22,615,813	2,484	207,661	9,096	22,823,474	2,509	9,096	22,823,474	2,509
TE-P47	6,758	8,545,881	1,265	102,017	6,774	8,647,898	1,277	6,774	8,647,898	1,277
TE-R51 + TE-R51A	17,636	672,153	38	(3,839)	17,636	668,314	38	17,636	668,314	38
TE-C52 & 52A	135,544	4,930,591	36	(3,891)	135,544	4,926,700	36	135,544	4,926,700	36
TE-P50	38,217	1,852,451	48	21,259	38,217	1,873,710	49	38,217	1,873,710	49
Lighting Unbilled		321,271								

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

		Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Distribution Id	Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
	Class Summary											
	Residential	277,207,565	137,555,516	(15,994,845)	275,887,975	122,880,261	327,768,312	122,880,261	35,885,492	8.7%	51,880,337	0.13
	General Service	184,360,130	79,302,841	(16,805,196)	184,448,887	62,408,888	180,501,853	62,408,888	(20,752,230)	-7.9%	(3,947,034)	(0.02)
	Large General Service	68,297,227	44,415,897	4,627,035	68,460,569	48,879,589	96,255,565	48,879,589	32,422,031	28.8%	27,794,996	0.24
	Large Power Service	52,048,597	46,025,186	(6,090,948)	52,159,816	39,823,018	56,404,499	39,823,018	(1,846,266)	-1.9%	4,244,682	0.05
	Transmission Service Rate	21,142,952	16,803,845	(7,498,838)	16,563,182	13,884,777	17,177,856	13,884,777	(6,884,163)	N/A	614,675	N/A
	Lighting	3,303,187	1,469,057	(160,637)	3,298,783	1,312,824	4,211,298	1,312,824	751,878	15.8%	912,515	0.20
	TOTAL COMPANY	606,359,658	325,572,341	(41,923,430)	600,819,212	289,189,357	682,319,384	289,189,357	39,576,741	4.2%	81,500,172	0.09
	Residential Schedules											
5000	TE-R-01	251,807,725	122,674,283	(11,419,908)	250,967,738	112,094,362	295,942,696	112,094,362	33,555,051	9.0%	44,974,958	0
5004	TE-201A	8,979,804	4,880,819	(1,392,678)	8,923,159	3,544,787	11,432,604	3,544,787	1,116,766	8.1%	2,509,444	0
5005	TE-201B	462,115	298,135	(109,885)	449,399	200,967	705,061	200,967	145,776	19.2%	255,661	0
5040	TE-R80	6,748,591	3,807,714	(651,171)	6,629,150	3,275,984	9,080,105	3,275,984	1,799,784	17.0%	2,450,955	0
5042	TE-R8	39,021	17,725	64,517	84,240	37,023	104,264	37,023	84,542	149.0%	20,025	0
5060	TE-R01BC	851,640	373,656	11,552	870,889	365,960	1,024,927	365,960	165,591	13.5%	154,038	0
	Lifeline Rate Schedules											
5002	TE4-01	187,990	89,256	(45,555)	175,417	56,273	185,728	56,273	(35,244)	-12.7%	10,311	0
5008	TE4-21	1,612	1,028	(383)	1,567	690	2,082	690	133	5.0%	515	0
5009	TE4-70	3,139	1,644	(579)	3,077	1,126	3,555	1,126	(101)	-2.1%	478	0
5010	TE5-01	571,226	277,370	(58,842)	547,423	242,331	682,552	242,331	76,286	9.0%	135,129	0
5012	TE5-21	1,242	807	(930)	738	381	1,091	381	(577)	-28.1%	353	0
5013	TE5-70	5,466	2,786	(996)	5,162	2,093	6,496	2,093	337	4.1%	1,333	0
5016	TE6-01	3,730,879	1,828,957	(947,785)	3,203,498	1,408,553	3,916,589	1,408,553	(234,694)	-4.2%	713,091	0
5017	TE6-21	12,269	7,969	(3,676)	10,790	5,771	16,750	5,771	2,283	11.3%	5,959	0
5022	TE6-70	43,687	23,012	(17,193)	34,101	15,405	44,943	15,405	(6,352)	-9.5%	10,842	0
5023	TE6-201A	169,675	102,562	(59,380)	149,713	63,144	221,542	63,144	12,448	4.6%	71,828	0
5024	TE6-201B	2,038	1,298	(675)	1,840	821	3,127	821	613	18.4%	1,288	0
5026	TE8-01	386,096	196,771	(104,360)	329,967	148,540	405,875	148,540	(28,452)	-4.9%	75,909	0
5027	TE8-21	4,771	3,238	(588)	4,722	2,697	7,841	2,697	2,530	31.6%	3,118	0
5028	TE8-70	9,942	5,317	(2,802)	8,887	3,570	11,270	3,570	(419)	-2.7%	2,383	0
5029	TE8-201A	7,659	4,895	(3,791)	6,028	2,734	9,675	2,734	(144)	-1.1%	3,647	0
5032	TE6-01BC	9,626	4,699	(2,413)	8,290	3,622	10,157	3,622	(546)	-3.8%	1,867	0
5033	TE-R-01LL	2,674,986	1,311,018	674,126	3,316,275	1,343,855	3,754,739	1,343,855	1,112,590	27.9%	438,464	0
5034	TE-R01LB	8,347	4,190	906	9,438	4,005	10,635	4,005	2,104	16.8%	1,197	0
5035	TE-201AL	74,180	40,970	24,262	102,638	36,774	127,263	36,774	48,887	42.5%	24,625	0
5036	TE-201BL	1,323	877	1,772	2,746	1,226	4,346	1,226	3,372	153.2%	1,600	0
5041	TE-R80LL	35,808	19,187	2,718	40,408	17,305	51,606	17,305	13,917	25.3%	11,199	0
5043	TE-R8LL	707	334	(106)	674	261	792	261	12	1.1%	118	0
	Residential Unbilled	376,000	1,575,000		Unbilled is included above		0	0	0	N/A	0	N/A

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

		Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Distribution Id	Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
	General Service											
5200	TE-GS10	153,865,268	63,703,857	(41,953,705)	155,070,441	20,544,978	65,151,321	20,544,978	(131,872,826)	-60.6%	(89,919,121)	(1)
5201	TE-GS11	3,524,955	1,819,452	(390,419)	3,367,260	1,586,729	4,126,388	1,586,729	368,709	6.9%	759,128	0
5213	TE-GS76	13,847,635	6,008,984	(5,198,250)	13,712,568	945,801	2,937,871	945,801	(15,972,947)	-80.4%	(10,774,696)	(1)
5225	TE-G10BC	420,954	145,939	(30,806)	427,972	108,116	55,008	108,116	(403,770)	-71.2%	(372,964)	(1)
5230	TE-GSM10	5,066,210	2,108,192	(1,402,754)	5,004,641	767,007	2,293,267	767,007	(4,114,128)	-57.3%	(2,711,374)	(0)
5231	TE-G10MBC	2,009,095	821,670	(454,729)	1,998,695	377,341	0	377,341	(2,453,424)	-86.7%	(1,998,695)	(1)
5240	TE-GS43	4,858,013	3,651,746	(328,561)	4,867,310	3,313,889	5,985,447	3,313,889	789,576	9.3%	1,118,137	0
XXXX	TE-MGS	0	0	30,392,039	0	30,392,039	87,418,562	30,392,039	117,810,601	N/A	87,418,562	N/A
XXXX	TE-MGSTOU	0	0	4,132,790	0	4,132,790	11,037,688	4,132,790	15,170,477	N/A	11,037,688	N/A
XXXX	TE-MGSBC					240,200	1,496,302	240,200	1,736,502	N/A	1,496,302	N/A
	General Service Unbilled	768,000	1,043,000		Unbilled is included above		0	0	0	N/A	0	N/A
	Large General Service											
5300	TE-LGS13	52,178,293	32,183,205	5,630,783	51,915,256	38,077,025	77,755,163	38,077,025	31,470,690	37.3%	25,839,906	0
5305	TE-LG85	15,878,358	10,579,443	(1,234,148)	15,386,190	9,837,463	15,912,213	9,837,463	(708,125)	-2.7%	526,023	0
5322	TE-L13BC	1,151,576	720,248	252,399	1,159,123	965,101	2,588,189	965,101	1,681,466	89.8%	1,429,066	1
	Large General Service Unbilled	(911,000)	933,000		Unbilled is included above		0	0	0	N/A	0	N/A
	Large Power Service											
5301	TE-LLP14	6,004,077	4,773,275	(5,019,433)	5,757,919	0	0	0	0	0.0%	N/A	N/A
5308	Special	882,693	777,092	(1,659,785)	0	0	0	0	0	0.0%	N/A	N/A
5309/5350	Large Power Service TOU	45,166,827	40,439,819	618,269	46,401,897	39,823,018	56,404,499	39,823,018	10,620,871	12.4%	10,002,602	0
	Industrial Unbilled	(5,000)	35,000		Unbilled is included above		0	0	0	N/A	0	N/A
	Transmission Service 138kV											
XXXX	TE-T138kV	21,142,952	16,803,845	(7,498,838)	16,563,182	13,884,777	17,177,856	13,884,777	(6,884,163)	N/A	614,675	N/A
	Lighting											
5400	TE-P41	1,076,513	846,600	(66,113)	1,086,397	770,603	1,371,965	770,603	219,455	11.4%	285,567	0
5401	TE-P47	406,784	319,997	(22,925)	411,640	292,215	519,842	292,215	85,277	11.7%	108,202	0
5011	TE-R51 + TE-R51A	145,242	25,118	(2,677)	145,228	22,455	187,063	22,455	39,158	23.0%	41,835	0
5203	TE-C52 & 52A	1,293,110	184,528	(21,641)	1,290,979	165,017	1,662,895	165,017	350,275	23.7%	371,916	0
5402	TE-P50	364,539	69,816	(7,282)	364,539	62,534	469,534	62,534	97,713	22.5%	104,994	0
	Lighting Unbilled	17,000	23,000		Unbilled is included above		0	0	0	N/A	0	N/A

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-R-01	**Residential Service**				
	Basic Service Charge Single Phase Per Mo.	$10.00	$15.00	$5.00	50%
	Basic Service Charge Three Phase Per Mo.	$15.00	$20.00	$5.00	33%
	Sum First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Sum 501-1,000 kWh	$0.067200	$0.079600	$0.012400	18%
	Sum 1,001-3,500 kWh	$0.079800	$0.079600	-$0.000200	0%
	Sum>3,500 kWh	$0.088200	$0.079600	-$0.008600	-10%
	Win First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Win 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win 1,001-3,500 kWh	$0.078100	$0.079600	$0.001500	2%
	Win>3,500 kWh	$0.087100	$0.079600	-$0.007500	-9%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
Solar Block Rate for Residential Electric Service Rate R-01		$0.053463	$0.054343	$0.000880	2%
TE-RXXX	**Residential Service Demand**				
	Basic Service Charge Per Month	N/M	$12.00	N/M	N/M
	Demand 0-7 kW	N/M	$8.75	N/M	N/M
	Demand > 7 kW	N/M	$12.50	N/M	N/M
	Sum kWh	N/M	$0.031740	N/M	N/M
	Win kWh	N/M	$0.031740	N/M	N/M
	Base Power Summer kWh	N/M	$0.035691	N/M	N/M
	Base Power Winter kWh	N/M	$0.032608	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-201A	**Special Residential Electric Service**				
	Basic Service Charge	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.050600	$0.063804	$0.013204	26%
	Sum 501-1,000 kWh	$0.060500	$0.079600	$0.019100	32%
	Sum 1,001-3,500 kWh	$0.071800	$0.079600	$0.007800	11%
	Sum>3,500 kWh	$0.079400	$0.079600	$0.000200	0.3%
	Win First 500 kWh	$0.050600	$0.063804	$0.013204	26%
	Win 501-1,000 kWh	$0.058700	$0.079600	$0.020900	36%
	Win 1,001-3,500 kWh	$0.070300	$0.079600	$0.009300	13%
	Win>3,500 kWh	$0.078400	$0.079600	$0.001200	2%
	Base Power Summer kWh	$0.035111	$0.028553	-$0.006558	-19%
	Base Power Winter kWh	$0.031532	$0.026086	-$0.005446	-17%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-201B	**Special Residential Electric Service Time of Use**				
	Basic Service Charge	$11.50	$12.00	$0.50	4%
	Sum On-peak First 500 kWh	$0.056800	$0.063804	$0.007004	12%
	Sum On-peak 501-1,000 kWh	$0.056800	$0.079600	$0.022800	40%
	Sum On-peak1,001-3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Sum On-peak >3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Sum Off-peak First 500 kWh	$0.044000	$0.063804	$0.019804	45%
	Sum Off-peak 501-1,000 kWh	$0.044000	$0.079600	$0.035600	81%
	Sum Off-peak1,001-3,500 kWh	$0.044000	$0.079600	$0.035600	81%
	Sum Off-peak >3,500 kWh	$0.044000	$0.079600	$0.035600	81%
	Win On-peak First 500 kWh	$0.048300	$0.063804	$0.015504	32%
	Win On-peak 501-1,000 kWh	$0.048300	$0.079600	$0.031300	65%
	Win On-peak1,001-3,500 kWh	$0.048300	$0.079600	$0.031300	65%
	Win On-peak >3,500 kWh	$0.048300	$0.079600	$0.031300	65%
	Win Off-peak First 500 kWh	$0.035500	$0.063804	$0.028304	80%
	Win Off-peak 501-1,000 kWh	$0.035500	$0.079600	$0.044100	124%
	Win Off-peak1,001-3,500 kWh	$0.035500	$0.079600	$0.044100	124%
	Win Off-peak >3,500 kWh	$0.035500	$0.079600	$0.044100	124%
	Base Power Summer On-Peak kWh	$0.050669	$0.053254	$0.002585	5%
	Base Power Summer Off-Peak kWh	$0.026679	$0.021066	-$0.005613	-21%
	Base Power Winter On-peak kWh	$0.032893	$0.026054	-$0.006839	-21%
	Base Power Winter Off-peak kWh	$0.027092	$0.020524	-$0.006568	-24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R80	**Residential Time of Use**				
	Basic Service Charge	$11.50	$12.00	$0.50	4%
	Sum On-peak First 500 kWh	$0.066800	$0.063804	-$0.002996	-4%
	Sum On-peak 501-1,000 kWh	$0.066800	$0.079600	$0.012800	19%
	Sum On-peak1,001-3,500 kWh	$0.066800	$0.079600	$0.012800	19%
	Sum On-peak >3,500 kWh	$0.066800	$0.079600	$0.012800	19%
	Sum Off-peak First 500 kWh	$0.051800	$0.063804	$0.012004	23%
	Sum Off-peak 501-1,000 kWh	$0.051800	$0.079600	$0.027800	54%
	Sum Off-peak1,001-3,500 kWh	$0.051800	$0.079600	$0.027800	54%
	Sum Off-peak >3,500 kWh	$0.051800	$0.079600	$0.027800	54%
	Win On-peak First 500 kWh	$0.056800	$0.063804	$0.007004	12%
	Win On-peak 501-1,000 kWh	$0.056800	$0.079600	$0.022800	40%
	Win On-peak1,001-3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Win On-peak >3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Win Off-peak First 500 kWh	$0.041800	$0.063804	$0.022004	53%
	Win Off-peak 501-1,000 kWh	$0.041800	$0.079600	$0.037800	90%
	Win Off-peak1,001-3,500 kWh	$0.041800	$0.079600	$0.037800	90%
	Win Off-peak >3,500 kWh	$0.041800	$0.079600	$0.037800	90%
	Base Power Summer On-Peak kWh	$0.050669	$0.066568	$0.015899	31%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026332	-$0.000347	-1%
	Base Power Winter On-peak kWh	$0.032893	$0.032568	-$0.000325	-1%
	Base Power Winter Off-peak kWh	$0.027092	$0.025655	-$0.001437	-5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-RXXX	**Residential Demand Time of Use**				
	Basic Service Charge Per Month	N/M	$12.00	N/M	N/M
	Demand 0-7 kW	N/M	$8.75	N/M	N/M
	Demand > 7 kW	N/M	$12.50	N/M	N/M
	Sum On-peak kWh	N/M	$0.031740	N/M	N/M
	Sum Off-peak kWh	N/M	$0.031740	N/M	N/M
	Win On-peak kWh	N/M	$0.031740	N/M	N/M
	Win Off-peak kWh	N/M	$0.031740	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.066568	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.026332	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.032568	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.025655	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-R8	**Residential Time of Use Super Peak**				
	Basic Service Charge	$11.50	$12.00	$0.50	4%
	Sum On-peak First 500 kWh	$0.097100	$0.063804	-$0.033296	-34%
	Sum On-peak 501-1,000 kWh	$0.097100	$0.079600	-$0.017500	-18%
	Sum On-peak1,001-3,500 kWh	$0.120100	$0.079600	-$0.040500	-34%
	Sum On-peak >3,500 kWh	$0.120100	$0.079600	-$0.040500	-34%
	Sum Off-peak First 500 kWh	$0.048500	$0.063804	$0.015304	32%
	Sum Off-peak 501-1,000 kWh	$0.048500	$0.079600	$0.031100	64%
	Sum Off-peak1,001-3,500 kWh	$0.071500	$0.079600	$0.008100	11%
	Sum Off-peak >3,500 kWh	$0.071500	$0.079600	$0.008100	11%
	Win On-peak First 500 kWh	$0.089100	$0.063804	-$0.025296	-28%
	Win On-peak 501-1,000 kWh	$0.089100	$0.079600	-$0.009500	-11%
	Win On-peak1,001-3,500 kWh	$0.112100	$0.079600	-$0.032500	-29%
	Win On-peak >3,500 kWh	$0.112100	$0.079600	-$0.032500	-29%
	Win Off-peak First 500 kWh	$0.038500	$0.063804	$0.025304	66%
	Win Off-peak 501-1,000 kWh	$0.038500	$0.079600	$0.041100	107%
	Win Off-peak1,001-3,500 kWh	$0.061500	$0.079600	$0.018100	29%
	Win Off-peak >3,500 kWh	$0.061500	$0.079600	$0.018100	29%
	Base Power Summer On-Peak kWh	$0.080100	$0.066568	-$0.013532	-17%
	Base Power Summer Off-Peak kWh	$0.022200	$0.026332	$0.004132	19%
	Base Power Winter On-peak kWh	$0.040200	$0.032568	-$0.007632	-19%
	Base Power Winter Off-peak kWh	$0.020500	$0.025655	$0.005155	25%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R01BC	**Residential Service R-01 Bright Community Solar**				
	Basic Service Charge Single Phase	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Sum 501-1,000 kWh	$0.067200	$0.079600	$0.012400	18%
	Sum 1,001-3,500 kWh	$0.079800	$0.079600	-$0.000200	0%
	Sum>3,500 kWh	$0.088200	$0.079600	-$0.008600	-10%
	Win First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Win 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win 1,001-3,500 kWh	$0.078100	$0.079600	$0.001500	2%
	Win>3,500 kWh	$0.087100	$0.079600	-$0.007500	-9%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE4-01	**Lifeline Residential Service Standard (Frozen 1996 - R-04-01F Senior % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Win First 500 kWh	$0.057000	$0.063804	$0.006804	12%
	Win 501-1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Win >1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Base Power Summer kWh	$0.033198	$0.035691	$0.002493	8%
	Base Power Winter kWh	$0.025698	$0.032608	$0.006910	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE4-21	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
	Basic Service Charge Per Month	$8.86	$12.00	$3.14	35%
	Sum On-Peak First 500 kWh	$0.078800	$0.063804	-$0.014996	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.079600	$0.000800	1%
	Sum On-Peak >1,000 kWh	$0.078800	$0.079600	$0.000800	1%
	Sum Off-Peak First 500 kWh	$0.030100	$0.063804	$0.033704	112%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Win On-Peak First 500 kWh	$0.065200	$0.063804	-$0.001396	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win On-Peak >1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win Off-Peak First 500 kWh	$0.033000	$0.063804	$0.030804	93%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Win Off-Peak >1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Base Power Summer On-Peak kWh	$0.053198	$0.066568	$0.013370	25%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE4-70	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
	Basic Service Charge Per Month	$8.78	$12.00	$3.22	37%
	Sum On-Peak First 500 kWh	$0.139300	$0.063804	-$0.075496	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum On-Peak >1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.063804	-$0.010196	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Off-Peak First 500 kWh	$0.037900	$0.063804	$0.025904	68%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Win On-Peak First 500 kWh	$0.092500	$0.063804	-$0.028696	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win On-Peak >1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win Off-Peak First 500 kWh	$0.024900	$0.063804	$0.038904	156%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Win Off-Peak >1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Base Power Summer On-Peak kWh	$0.055698	$0.066568	$0.010870	20%
	Base Power Summer Shoulder kWh	$0.048198	$0.066568	$0.018370	38%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE5-01	**Lifeline Residential Service Standard (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Win First 500 kWh	$0.057000	$0.063804	$0.006804	12%
	Win 501-1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Win >1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Base Power Summer kWh	$0.033198	$0.035691	$0.002493	8%
	Base Power Winter kWh	$0.025698	$0.032608	$0.006910	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE5-21	**Residential Time of Use (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$8.86	$12.00	$3.14	35%
	Sum On-Peak First 500 kWh	$0.078800	$0.063804	-$0.014996	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.079600	$0.000800	1.0%
	Sum On-Peak >1,000 kWh	$0.078800	$0.079600	$0.000800	1.0%
	Sum Off-Peak First 500 kWh	$0.030100	$0.063804	$0.033704	112.0%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Win On-Peak First 500 kWh	$0.065200	$0.063804	-$0.001396	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win On-Peak >1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win Off-Peak First 500 kWh	$0.033000	$0.063804	$0.030804	93%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Win Off-Peak >1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Base Power Summer On-Peak kWh	$0.053198	$0.066568	$0.013370	25%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE5-70	**Residential Time of Use (Frozen Lifeline % Discount)**				
	Basic Service Charge Per Month	$8.78	$12.00	$3.22	37%
	Sum On-Peak First 500 kWh	$0.139300	$0.063804	-$0.075496	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum On-Peak >1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.063804	-$0.010196	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Off-Peak First 500 kWh	$0.037900	$0.063804	$0.025904	68%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Win On-Peak First 500 kWh	$0.092500	$0.063804	-$0.028696	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win On-Peak >1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win Off-Peak First 500 kWh	$0.024900	$0.063804	$0.038904	156%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Win Off-Peak >1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Base Power Summer On-Peak kWh	$0.055698	$0.066568	$0.010870	20%
	Base Power Summer Shoulder kWh	$0.048198	$0.066568	$0.018370	38%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE6-01	**Residential Service Standard (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Win First 500 kWh	$0.057000	$0.063804	$0.006804	12%
	Win 501-1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Win >1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Base Power Summer kWh	$0.033198	$0.035691	$0.002493	8%
	Base Power Winter kWh	$0.025698	$0.032608	$0.006910	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-21	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.86	$12.00	$3.14	35%
	Sum On-Peak First 500 kWh	$0.078800	$0.063804	-$0.014996	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.079600	$0.000800	1%
	Sum On-Peak >1,000 kWh	$0.078800	$0.079600	$0.000800	1%
	Sum Off-Peak First 500 kWh	$0.030100	$0.063804	$0.033704	112%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Win On-Peak First 500 kWh	$0.065200	$0.063804	-$0.001396	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win On-Peak >1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win Off-Peak First 500 kWh	$0.033000	$0.063804	$0.030804	93%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Win Off-Peak >1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Base Power Summer On-Peak kWh	$0.053198	$0.066568	$0.013370	25%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-70	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.78	$12.00	$3.22	37%
	Sum On-Peak First 500 kWh	$0.139300	$0.063804	-$0.075496	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum On-Peak >1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.063804	-$0.010196	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Off-Peak First 500 kWh	$0.037900	$0.063804	$0.025904	68%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Win On-Peak First 500 kWh	$0.092500	$0.063804	-$0.028696	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win On-Peak >1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win Off-Peak First 500 kWh	$0.024900	$0.063804	$0.038904	156%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Win Off-Peak >1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Base Power Summer On-Peak kWh	$0.055698	$0.066568	$0.010870	20%
	Base Power Summer Shoulder kWh	$0.048198	$0.066568	$0.018370	38%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE6-201A	**Special Residential Service (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Mid Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Mid Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Mid Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Remain Sum First 500 kWh	$0.043600	$0.063804	$0.020204	46%
	Remain Sum 501-1,000 kWh	$0.043600	$0.079600	$0.036000	83%
	Remain Sum >1,000 kWh	$0.043600	$0.079600	$0.036000	83%
	Win First 500 kWh	$0.041300	$0.063804	$0.022504	54%
	Win 501-1,000 kWh	$0.041300	$0.079600	$0.038300	93%
	Win >1,000 kWh	$0.041300	$0.079600	$0.038300	93%
	Base Power Mid Summer kWh	$0.033198	$0.028553	-$0.004645	-14%
	Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
	Base Power Winter kWh	$0.027198	$0.026086	-$0.001112	-4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-201B	**Special Residential Service Time of Use (Frozen Lifeline Flat Discount)**				
	Basic Service Charge Per Month	$8.78	$12.00	$3.22	37%
	Mid Sum On-Peak First 500 kWh	$0.136900	$0.063804	-$0.073096	-53%
	Mid Sum On-Peak 501-1,000 kWh	$0.136900	$0.079600	-$0.057300	-42%
	Mid Sum On-Peak >1,000 kWh	$0.136900	$0.079600	-$0.057300	-42%
	Mid Sum Shlder-Peak First 500 kWh	$0.074700	$0.063804	-$0.010896	-15%
	Mid Sum Shldr-Peak 501-1,000 kWh	$0.074700	$0.079600	$0.004900	7%
	Mid Sum Shldr-Peak >1,000 kWh	$0.074700	$0.079600	$0.004900	7%
	Mid Sum Off-Peak First 500 kWh	$0.038300	$0.063804	$0.025504	67%
	Mid Sum Off-Peak 501-1,000 kWh	$0.038300	$0.079600	$0.041300	108%
	Mid Sum Off-Peak >1,000 kWh	$0.038300	$0.079600	$0.041300	108%
	Remain Sum On-Peak First 500 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum On-Peak 501-1,000 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum On-Peak >1,000 kWh	$0.099500	$0.000000	-$0.099500	-100%
	Remain Sum Shlder-Peak First 500 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Shldr-Peak 501-1,000 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Shldr-Peak >1,000 kWh	$0.048600	$0.000000	-$0.048600	-100%
	Remain Sum Off-Peak First 500 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Remain Sum Off-Peak 501-1,000 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Remain Sum Off-Peak >1,000 kWh	$0.025300	$0.000000	-$0.025300	-100%
	Win On-Peak First 500 kWh	$0.065200	$0.063804	-$0.001396	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win On-Peak >1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win Off-Peak First 500 kWh	$0.015300	$0.063804	$0.048504	317%
	Win Off-Peak 501-1,000 kWh	$0.015300	$0.079600	$0.064300	420%
	Win Off-Peak >1,000 kWh	$0.015300	$0.079600	$0.064300	420%
	Base Power Mid Summer On-Peak kWh	$0.055698	$0.056583	$0.000885	2%
	Base Power Mid Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
	Base Power Mid Summer Off-Peak kWh	$0.023198	$0.022382	-$0.000816	-4%
	Base Power Remaining Summer On-Peak kWh	$0.055698	$0.000000	-$0.055698	-100%
	Base Power Remaining Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
	Base Power Remaining Summer Off-Peak kWh	$0.023198	$0.000000	-$0.023198	-100%
	Base Power Winter On-Peak kWh	$0.040698	$0.027683	-$0.013015	-32%
	Base Power Winter Off-Peak kWh	$0.020698	$0.021807	$0.001109	5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE8-01	**Residential Service Standard (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Win First 500 kWh	$0.057000	$0.063804	$0.006804	12%
	Win 501-1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Win >1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Base Power Summer kWh	$0.033198	$0.035691	$0.002493	8%
	Base Power Winter kWh	$0.025698	$0.032608	$0.006910	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE8-21	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$8.86	$12.00	$3.14	35%
	Sum On-Peak First 500 kWh	$0.078800	$0.063804	-$0.014996	-19%
	Sum On-Peak 501-1,000 kWh	$0.078800	$0.079600	$0.000800	1%
	Sum On-Peak >1,000 kWh	$0.078800	$0.079600	$0.000800	1%
	Sum Off-Peak First 500 kWh	$0.030100	$0.063804	$0.033704	112%
	Sum Off-Peak 501-1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Sum Off-Peak >1,000 kWh	$0.030100	$0.079600	$0.049500	164%
	Win On-Peak First 500 kWh	$0.065200	$0.063804	-$0.001396	-2%
	Win On-Peak 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win On-Peak >1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win Off-Peak First 500 kWh	$0.033000	$0.063804	$0.030804	93%
	Win Off-Peak 501-1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Win Off-Peak >1,000 kWh	$0.033000	$0.079600	$0.046600	141%
	Base Power Summer On-Peak kWh	$0.053198	$0.066568	$0.013370	25%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE8-70	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$8.78	$12.00	$3.22	37%
	Sum On-Peak First 500 kWh	$0.139300	$0.063804	-$0.075496	-54%
	Sum On-Peak 501-1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum On-Peak >1,000 kWh	$0.139300	$0.079600	-$0.059700	-43%
	Sum Shldr-Peak First 500 kWh	$0.074000	$0.063804	-$0.010196	-14%
	Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Shldr-Peak >1,000 kWh	$0.074000	$0.079600	$0.005600	8%
	Sum Off-Peak First 500 kWh	$0.037900	$0.063804	$0.025904	68%
	Sum Off-Peak 501-1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Sum Off-Peak >1,000 kWh	$0.037900	$0.079600	$0.041700	110%
	Win On-Peak First 500 kWh	$0.092500	$0.063804	-$0.028696	-31%
	Win On-Peak 501-1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win On-Peak >1,000 kWh	$0.092500	$0.079600	-$0.012900	-14%
	Win Off-Peak First 500 kWh	$0.024900	$0.063804	$0.038904	156%
	Win Off-Peak 501-1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Win Off-Peak >1,000 kWh	$0.024900	$0.079600	$0.054700	220%
	Base Power Summer On-Peak kWh	$0.055698	$0.066568	$0.010870	20%
	Base Power Summer Shoulder kWh	$0.048198	$0.066568	$0.018370	38%
	Base Power Summer Off-Peak kWh	$0.023198	$0.026332	$0.003134	14%
	Base Power Winter On-peak kWh	$0.040698	$0.032568	-$0.008130	-20%
	Base Power Winter Off-peak kWh	$0.020698	$0.025655	$0.004957	24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE8-201A	**Special Residential Service (Frozen Lifeline Medical % Discount)**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Mid Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Mid Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Mid Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Remain Sum First 500 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Remain Sum 501-1,000 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Remain Sum >1,000 kWh	$0.043600	$0.000000	-$0.043600	-100%
	Win First 500 kWh	$0.041300	$0.063804	$0.022504	54%
	Win 501-1,000 kWh	$0.041300	$0.079600	$0.038300	93%
	Win >1,000 kWh	$0.041300	$0.079600	$0.038300	93%
	Base Power Mid Summer kWh	$0.033198	$0.028553	-$0.004645	-14%
	Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
	Base Power Winter kWh	$0.027198	$0.026086	-$0.001112	-4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE6-01BC	**Residential Service Standard (Frozen Lifeline Flat Discount) Bright Community Solar**				
	Basic Service Charge Per Month	$6.90	$15.00	$8.10	117%
	Sum First 500 kWh	$0.061100	$0.063804	$0.002704	4%
	Sum 501-1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Sum >1,000 kWh	$0.061100	$0.079600	$0.018500	30%
	Win First 500 kWh	$0.057000	$0.063804	$0.006804	12%
	Win 501-1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Win >1,000 kWh	$0.057000	$0.079600	$0.022600	40%
	Base Power Summer kWh	$0.033198	$0.035691	$0.002493	8%
	Base Power Winter kWh	$0.025698	$0.032608	$0.006910	27%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R-01LL	**Residential Service Standard**				
	Basic Service Charge Per Month	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Sum 501-1,000 kWh	$0.067200	$0.079600	$0.012400	18%
	Sum 1,001-3,500 kWh	$0.079800	$0.079600	-$0.000200	0%
	Sum>3,500 kWh	$0.088200	$0.079600	-$0.008600	-10%
	Win First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Win 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win 1,001-3,500 kWh	$0.078100	$0.079600	$0.001500	2%
	Win>3,500 kWh	$0.087100	$0.079600	-$0.007500	-9%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R01LB	**Residential Service R-01 Bright Community Solar**				
	Basic Service Charge Per Month	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Sum 501-1,000 kWh	$0.067200	$0.079600	$0.012400	18%
	Sum 1,001-3,500 kWh	$0.079800	$0.079600	-$0.000200	0%
	Sum>3,500 kWh	$0.088200	$0.079600	-$0.008600	-10%
	Win First 500 kWh	$0.056200	$0.063804	$0.007604	14%
	Win 501-1,000 kWh	$0.065200	$0.079600	$0.014400	22%
	Win 1,001-3,500 kWh	$0.078100	$0.079600	$0.001500	2%
	Win>3,500 kWh	$0.087100	$0.079600	-$0.007500	-9%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-201AL	**Special Residential Electric Service**				
	Basic Service Charge Per Month	$10.00	$15.00	$5.00	50%
	Sum First 500 kWh	$0.050600	$0.063804	$0.013204	26%
	Sum 501-1,000 kWh	$0.060500	$0.079600	$0.019100	32%
	Sum 1,001-3,500 kWh	$0.071800	$0.079600	$0.007800	11%
	Sum>3,500 kWh	$0.079400	$0.079600	$0.000200	0%
	Win First 500 kWh	$0.050600	$0.063804	$0.013204	26%
	Win 501-1,000 kWh	$0.058700	$0.079600	$0.020900	36%
	Win 1,001-3,500 kWh	$0.070300	$0.079600	$0.009300	13%
	Win>3,500 kWh	$0.078400	$0.079600	$0.001200	2%
	Base Power Summer kWh	$0.035111	$0.028553	-$0.006558	-19%
	Base Power Winter kWh	$0.031532	$0.026086	-$0.005446	-17%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-201BL	**Residential Time of Use**				
	Basic Service Charge Per Month	$11.50	$12.00	$0.50	4%
	Sum On-peak First 500 kWh	$0.056800	$0.063804	$0.007004	12%
	Sum On-peak 501-1,000 kWh	$0.056800	$0.079600	$0.022800	40%
	Sum On-peak1,001-3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Sum On-peak >3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Sum Off-peak First 500 kWh	$0.044000	$0.063804	$0.019804	45%
	Sum Off-peak 501-1,000 kWh	$0.044000	$0.079600	$0.035600	81%
	Sum Off-peak1,001-3,500 kWh	$0.044000	$0.079600	$0.035600	81%
	Sum Off-peak >3,500 kWh	$0.044000	$0.079600	$0.035600	81%
	Win On-peak First 500 kWh	$0.048300	$0.063804	$0.015504	32%
	Win On-peak 501-1,000 kWh	$0.048300	$0.079600	$0.031300	65%
	Win On-peak1,001-3,500 kWh	$0.048300	$0.079600	$0.031300	65%
	Win On-peak >3,500 kWh	$0.048300	$0.079600	$0.031300	65%
	Win Off-peak First 500 kWh	$0.035500	$0.063804	$0.028304	80%
	Win Off-peak 501-1,000 kWh	$0.035500	$0.079600	$0.044100	124%
	Win Off-peak1,001-3,500 kWh	$0.035500	$0.079600	$0.044100	124%
	Win Off-peak >3,500 kWh	$0.035500	$0.079600	$0.044100	124%
	Base Power Summer On-Peak kWh	$0.050669	$0.053254	$0.002585	5%
	Base Power Summer Off-Peak kWh	$0.026679	$0.021066	-$0.005613	-21%
	Base Power Winter On-peak kWh	$0.032893	$0.026054	-$0.006839	-21%
	Base Power Winter Off-peak kWh	$0.027092	$0.020524	-$0.006568	-24%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-R80LL	**Residential Time of Use**				
	Basic Service Charge Per Month	$11.50	$12.00	$0.50	4%
	Sum On-peak First 500 kWh	$0.066800	$0.063804	-$0.002996	-4%
	Sum On-peak 501-1,000 kWh	$0.066800	$0.079600	$0.012800	19%
	Sum On-peak1,001-3,500 kWh	$0.066800	$0.079600	$0.012800	19%
	Sum On-peak >3,500 kWh	$0.066800	$0.079600	$0.012800	19%
	Sum Off-peak First 500 kWh	$0.051800	$0.063804	$0.012004	23%
	Sum Off-peak 501-1,000 kWh	$0.051800	$0.079600	$0.027800	54%
	Sum Off-peak1,001-3,500 kWh	$0.051800	$0.079600	$0.027800	54%
	Sum Off-peak >3,500 kWh	$0.051800	$0.079600	$0.027800	54%
	Win On-peak First 500 kWh	$0.056800	$0.063804	$0.007004	12%
	Win On-peak 501-1,000 kWh	$0.056800	$0.079600	$0.022800	40%
	Win On-peak1,001-3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Win On-peak >3,500 kWh	$0.056800	$0.079600	$0.022800	40%
	Win Off-peak First 500 kWh	$0.041800	$0.063804	$0.022004	53%
	Win Off-peak 501-1,000 kWh	$0.041800	$0.079600	$0.037800	90%
	Win Off-peak1,001-3,500 kWh	$0.041800	$0.079600	$0.037800	90%
	Win Off-peak >3,500 kWh	$0.041800	$0.079600	$0.037800	90%
	Base Power Summer On-Peak kWh	$0.050669	$0.066568	$0.015899	31%
	Base Power Summer Off-Peak kWh	$0.026679	$0.026332	-$0.000347	-1%
	Base Power Winter On-peak kWh	$0.032893	$0.032568	-$0.000325	-1%
	Base Power Winter Off-peak kWh	$0.027092	$0.025655	-$0.001437	-5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-R8LL	**Residential Time of Use Super Peak Lifeline**				
	Basic Service Charge Per Month	$11.50	$12.00	$0.50	4%
	Sum On-peak First 500 kWh	$0.097100	$0.063804	-$0.033296	-34%
	Sum On-peak 501-1,000 kWh	$0.097100	$0.079600	-$0.017500	-18%
	Sum On-peak1,001-3,500 kWh	$0.120100	$0.079600	-$0.040500	-34%
	Sum On-peak >3,500 kWh	$0.120100	$0.079600	-$0.040500	-34%
	Sum Off-peak First 500 kWh	$0.048500	$0.063804	$0.015304	32%
	Sum Off-peak 501-1,000 kWh	$0.048500	$0.079600	$0.031100	64%
	Sum Off-peak1,001-3,500 kWh	$0.071500	$0.079600	$0.008100	11%
	Sum Off-peak >3,500 kWh	$0.071500	$0.079600	$0.008100	11%
	Win On-peak First 500 kWh	$0.089100	$0.063804	-$0.025296	-28%
	Win On-peak 501-1,000 kWh	$0.089100	$0.079600	-$0.009500	-11%
	Win On-peak1,001-3,500 kWh	$0.112100	$0.079600	-$0.032500	-29%
	Win On-peak >3,500 kWh	$0.112100	$0.079600	-$0.032500	-29%
	Win Off-peak First 500 kWh	$0.038500	$0.063804	$0.025304	66%
	Win Off-peak 501-1,000 kWh	$0.038500	$0.079600	$0.041100	107%
	Win Off-peak1,001-3,500 kWh	$0.061500	$0.079600	$0.018100	29%
	Win Off-peak >3,500 kWh	$0.061500	$0.079600	$0.018100	29%
	Base Power Summer On-Peak kWh	$0.080100	$0.066568	-$0.013532	-17%
	Base Power Summer Off-Peak kWh	$0.022200	$0.026332	$0.004132	19%
	Base Power Winter On-peak kWh	$0.040200	$0.032568	-$0.007632	-19%
	Base Power Winter Off-peak kWh	$0.020500	$0.025655	$0.005155	25%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-PESXX	**Prepay Electric Service**				
	Basic Service Charge Per Day	N/M	$0.67	N/M	N/M
	Sum First 20 kWh Per Day	N/M	$0.063804	N/M	N/M
	Sum >20 kWh Per Day	N/M	$0.079600	N/M	N/M
	Win First 20 kWh Per Day	N/M	$0.063804	N/M	N/M
	Win >20 kWh Per Day	N/M	$0.079600	N/M	N/M
	Base Power Summer kWh	N/M	$0.035691	N/M	N/M
	Base Power Winter kWh	N/M	$0.032608	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-GS10	**Small General Service**				
	Basic Service Charge Single Phase Per Mo.	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Mo.	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.086250	$0.009250	12%
	Sum >500 kWh	$0.097800	$0.101100	$0.003300	3%
	Win First 500 kWh	$0.057000	$0.066300	$0.009300	16%
	Win >500 kWh	$0.079000	$0.087300	$0.008300	11%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GSXX	**Small General Service Demand**				
	Basic Service Charge Per Month	N/M	$22.00	N/M	N/M
	Demand 0-7 kW	N/M	$9.95	N/M	N/M
	Demand > 7 kW	N/M	$13.50	N/M	N/M
	Sum kWh	N/M	$0.063890	N/M	N/M
	Win kWh	N/M	$0.053890	N/M	N/M
	Base Power Summer kWh	N/M	$0.035691	N/M	N/M
	Base Power Winter kWh	N/M	$0.032608	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-GS11	**Mobile Home Park Service (FROZEN)**				
	Basic Service Charge Single Phase Per Mo.	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Mo.	$20.50	$32.00	$11.50	56%
	Sum kWh	$0.082000	$0.086940	$0.004940	6%
	Win kWh	$0.062000	$0.086940	$0.024940	40%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS76	**Small General Service Time of Use**				
	Basic Service Charge	$17.50	$22.00	$4.50	26%
	Sum On-peak First 500 kWh	$0.099100	$0.086250	-$0.012850	-13%
	Sum On-peak >500 kWh	$0.099100	$0.101100	$0.002000	2%
	Sum Off-peak First 500 kWh	$0.084900	$0.086250	$0.001350	2%
	Sum Off-peak >500 kWh	$0.084900	$0.101100	$0.016200	19%
	Winter On-peak First 500 kWh	$0.081400	$0.066300	-$0.015100	-19%
	Winter On-peak >500 kWh	$0.081400	$0.087300	$0.005900	7%
	Winter Off-Peak First 500 kWh	$0.064900	$0.066300	$0.001400	2%
	Winter Off-Peak >500 kWh	$0.064900	$0.087300	$0.022400	35%
	Base Power Summer On-Peak kWh	$0.050669	$0.071322	$0.020653	41%
	Base Power Summer Off-Peak kWh	$0.026679	$0.025609	-$0.001070	-4%
	Base Power Winter On-peak kWh	$0.032893	$0.038010	$0.005117	16%
	Base Power Winter Off-peak kWh	$0.027092	$0.025655	-$0.001437	-5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
Solar Block Rate for Small General Service Rate GS-10		$0.053274	$0.054145	$0.000871	2%

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-GSXXX	**Small General Service Demand Time of Use**				
	Basic Service Charge Per Month	N/M	$22.00	N/M	N/M
	Demand 0-7 kW	N/M	$9.95	N/M	N/M
	Demand > 7 kW	N/M	$13.50	N/M	N/M
	Sum On-peak kWh	N/M	$0.063890	N/M	N/M
	Sum Off-peak kWh	N/M	$0.063890	N/M	N/M
	Win On-peak kWh	N/M	$0.053890	N/M	N/M
	Win Off-peak kWh	N/M	$0.053890	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.071322	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.025609	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.038010	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.025655	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-G10BC	**General Service Bright Community Solar**				
	Basic Service Charge Single Phase Per Month	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Month	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.086250	$0.009250	12%
	Sum>500 kWh	$0.097800	$0.101100	$0.003300	3%
	Winter First 500 kWh 0568	$0.057000	$0.066300	$0.009300	16%
	Winter >500 kWh 0788	$0.079000	$0.087300	$0.008300	11%
	Winter First 500 kWh 0570	$0.057000	$0.000000	-$0.057000	-100%
	Winter >500 kWh 0790	$0.079000	$0.000000	-$0.079000	-100%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	Solar Blocks kWh_2011	$0.028475	$0.028475	$0.000000	0%
	Solar Blocks kWh_2013	$0.033274	$0.033274	$0.000000	0%
	Solar Blocks kWh_20xx	$0.028475	$0.028475	$0.000000	0%
	Credited Solar Blocks kWh_2011	-$0.028475	-$0.028475	$0.000000	0%
	Credited Solar Blocks kWh_2013	-$0.033274	-$0.033274	$0.000000	0%
	Credited Solar Blocks kWh_20xx	-$0.028475	-$0.028475	$0.000000	0%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GSM10	**Small General Service (Municipal Transitional Adjustment)**				
	Basic Service Charge Single Phase Per Month	$15.50	$27.00	$11.50	74%
	Basic Service Charge Three Phase Per Month	$20.50	$32.00	$11.50	56%
	Sum First 500 kWh	$0.077000	$0.086250	$0.009250	12%
	Sum>500 kWh	$0.097800	$0.101100	$0.003300	3%
	Win First 500 kWh	$0.057000	$0.066300	$0.009300	16%
	Win>500 kWh	$0.079000	$0.087300	$0.008300	11%
	Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-G10MBC	**General Service (Municipal Transitional Adjustment) Bright Community Solar**				
	Basic Service Charge Three Phase Per Month	$20.50	$27.00	$6.50	32%
	Sum First 500 kWh	$0.077000	$0.086250	$0.009250	12%
	Sum>500 kWh	$0.097800	$0.101100	$0.003300	3%
	Win First 500 kWh	$0.057000	$0.066300	$0.009300	16%
	Win>500 kWh	$0.079000	$0.087300	$0.008300	11%
	Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
	RT 43 Water Pumping				
TE-GS36	GS-36 (43) Water Pumping-Firm Service				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.068000	$0.076099	$0.008099	12%
	Win kWh	$0.048000	$0.060299	$0.012299	26%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS37	GS-37 Com Water Pumping-Firm w/ Primary Voltage Discount				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.064600	$0.072294	$0.007694	12%
	Win kWh	$0.045600	$0.057284	$0.011684	26%
	Base Power Summer kWh	$0.033355	$0.033906	$0.000551	2%
	Base Power Winter kWh	$0.029955	$0.030978	$0.001022	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS38	GS-38 (43) Water Pumping-Interruptible Serv				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.042000	$0.050100	$0.008100	19%
	Win kWh	$0.027000	$0.039300	$0.012300	46%
	Base Power Summer kWh	$0.031310	$0.031900	$0.000590	2%
	Base Power Winter kWh	$0.028420	$0.029500	$0.001080	4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-GS39	GS-39 (43) Water Pumping-Interupt w/Primary Voltage Discount				
	Basic Service Charge Per Mo.	$15.50	$27.00	$11.50	74%
	Sum kWh	$0.039900	$0.047600	$0.007700	19%
	Win kWh	$0.025650	$0.037300	$0.011650	45%
	Base Power Summer kWh	$0.029745	$0.030305	$0.000560	2%
	Base Power Winter kWh	$0.026999	$0.028025	$0.001026	4%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-MGS	**Medium General Service**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Summer Demand Charge Per kW	N/M	$6.75	N/M	N/M
	Winter Demand Charge Per kW	N/M	$5.00	N/M	N/M
	Summer kWh	N/M	$0.080790	N/M	N/M
	Winter kWh	N/M	$0.067790	N/M	N/M
	Base Power Summer kWh	N/M	$0.035691	N/M	N/M
	Base Power Winter kWh	N/M	$0.032608	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
Solar Block Rate for Medium General Service Rate MGS		$0.053227	0.054129		

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-MGSTOU	**Medium General Service TOU**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Demand Summer On-Peak per kW	N/M	$7.75	N/M	N/M
	Demand Summer Off-Peak Excess Per kW	N/M	$3.45	N/M	N/M
	Demand Winter On-Peak Per kW	N/M	$3.35	N/M	N/M
	Demand Winter Off-Peak Excess Per kW	N/M	$2.85	N/M	N/M
	Summer On-Peak kWh	N/M	$0.110800	N/M	N/M
	Summer Off-Peak kWh	N/M	$0.060100	N/M	N/M
	Winter On-Peak kWh	N/M	$0.110800	N/M	N/M
	Winter Off-Peak kWh	N/M	$0.060100	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.071322	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.025609	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.038010	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.025655	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-MGSBC	**Medium General Service Bright Community solar**				
	Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
	Summer Demand Charge Per kW	N/M	$6.75	N/M	N/M
	Winter Demand Charge Per kW	N/M	$5.00	N/M	N/M
	Summer kWh	N/M	$0.080790	N/M	N/M
	Winter kWh	N/M	$0.067790	N/M	N/M
	Base Power Summer kWh	N/M	$0.035691	N/M	N/M
	Base Power Winter kWh	N/M	$0.032608	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-LGS13	**Large General Service**				
	Basic Service Charge Per Month	$775.00	$950.00	$175.00	23%
	Demand Charge Per kW	$15.25	$17.40	$2.15	14%
	Summer kWh	$0.0192	$0.0185	-$0.000670	-3%
	Winter kWh	$0.0134	$0.0143	$0.000900	7%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-LG85	**Large General Service TOU**				
	Basic Service Charge Per Month	$950.00	$950.00	$0.00	0%
	Demand Summer On-Peak per kW	$14.55	$22.15	$7.60	52%
	Demand Summer Off-Peak Per kW	$10.92	$10.92	$0.00	0%
	Demand Winter On-Peak Per kW	$11.59	$18.50	$6.91	60%
	Demand Winter Off-Peak Per kW	$9.10	$9.10	$0.00	0%
	Summer On-Peak kWh	$0.008600	$0.018540	$0.009940	116%
	Summer Off-Peak kWh	$0.006000	$0.012700	$0.006700	112%
	Winter On-Peak kWh	$0.003000	$0.007100	$0.004100	137%
	Winter Off-Peak kWh	$0.000500	$0.001250	$0.000750	150%
	Base Power Summer On-Peak kWh	$0.050669	$0.071322	$0.020653	41%
	Base Power Summer Off-Peak kWh	$0.026679	$0.025609	-$0.001070	-4%
	Base Power Winter On-peak kWh	$0.032893	$0.038010	$0.005117	16%
	Base Power Winter Off-peak kWh	$0.027092	$0.025655	-$0.001437	-5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-L13BC	**Large General Service Brigh Community Solar**				
	Basic Service Charge Per Month	$775.00	$950.00	$175.00	23%
	Demand Charge Per kW	$15.25	$17.40	$2.15	14%
	Summer kWh	$0.0192	$0.0185	-$0.000670	-3%
	Winter kWh	$0.0134	$0.0143	$0.000900	7%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	Solar_Blocks_kWh_053227_2P	$0.033227	$0.033227	$0.000000	0%

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
	Solar_Blocks_kWh_039371_1_1P	$0.029371	$0.029371	$0.000000	0%
	Credited_Blocks_kWh_039371_1_1P	-$0.029371	-$0.029371	$0.000000	0%
	Solar_Blocks_kWh_039371_2_1P	$0.029371	$0.029371	$0.000000	0%
	Credited_Blocks_kWh_039371_2_1P	-$0.029371	-$0.029371	$0.000000	0%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-LLP14	**Large Light & Power**		TARIFF CLOSED	TARIFF CLOSED	
	Basic Service Charge	$1,800.00	N/M	N/M	N/M
	Demand Charge	21.98	N/M	N/M	N/M
	Summer kWh	0.0032	N/M	N/M	N/M
	Winter kWh	0.0021	N/M	N/M	N/M
	Base Power Summer kWh	0.031611	N/M	N/M	N/M
	Base Power Winter kWh	0.028388	N/M	N/M	N/M
	PPFAC Charge kWh	$0.006820	N/M	N/M	N/M
TE-LLP90	Large Power Service Time of Use				
	Basic Service Charge Per Month	$2,000.00	$10,000.00	$8,000.00	400%
	Demand Summer On-Peak per kW	$20.49	$21.55	$1.06	5%
	Demand Summer Off-Peak Excess Per kW	$12.49	$14.69	$2.20	18%
	Demand Winter On-Peak Per kW	$15.49	$17.00	$1.51	10%
	Demand Winter Off-Peak Excess Per kW	$9.99	$14.58	$4.59	46%
	Summer On-Peak kWh	$0.006900	$0.007000	$0.000100	1%
	Summer Off-Peak kWh	$0.006500	$0.007000	$0.000500	8%
	Winter On-Peak kWh	$0.007500	$0.007000	-$0.000500	-7%
	Winter Off-Peak kWh	$0.007100	$0.007000	-$0.000100	-1%
	Base Power Summer On-Peak kWh	$0.045568	$0.052350	$0.006782	15%
	Base Power Summer Off-Peak kWh	$0.023985	$0.025760	$0.001775	7%
	Base Power Winter On-peak kWh	$0.029581	$0.033550	$0.003969	13%
	Base Power Winter Off-peak kWh	$0.024352	$0.025660	$0.001308	5%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M
TE-138	Transmission Service Rate 138kV				
	Basic Service Charge Per Month	N/M	$15,000.00	N/M	N/M
	Demand Summer On-Peak per kW	N/M	$19.72	N/M	N/M
	Demand Summer Off-Peak Excess Per kW	N/M	$14.69	N/M	N/M
	Demand Winter On-Peak Per kW	N/M	$17.00	N/M	N/M
	Demand Winter Off-Peak Excess Per kW	N/M	$14.58	N/M	N/M
	Summer On-Peak kWh	N/M	$0.007000	N/M	N/M
	Summer Off-Peak kWh	N/M	$0.007000	N/M	N/M
	Winter On-Peak kWh	N/M	$0.007000	N/M	N/M
	Winter Off-Peak kWh	N/M	$0.007000	N/M	N/M
	Base Power Summer On-Peak kWh	N/M	$0.051300	N/M	N/M
	Base Power Summer Off-Peak kWh	N/M	$0.024990	N/M	N/M
	Base Power Winter On-peak kWh	N/M	$0.032880	N/M	N/M
	Base Power Winter Off-peak kWh	N/M	$0.024890	N/M	N/M
	PPFAC Charge kWh	N/M	$0.000000	N/M	N/M
TE-P41&P47	P41 Traffic Signal & Street Lighting				
	Basic Service Charge Per Month	$0.00	$0.00	$0.00	0%
	All Delivery kWh	$0.047600	$0.060112	$0.012512	26%
	Base Power Summer kWh	$0.035111	$0.035691	$0.000580	2%
	Base Power Winter kWh	$0.031532	$0.032608	$0.001076	3%
	PPFAC Charge kWh	$0.006820	$0.000000	N/M	N/M

Rate Id	Rate Description and UOM	Present Rates	Proposed Rates	Increase $	Increase %
TE-P50	Lighting Service				
TE-R51 + TE-R	100OH	$8.19	$10.55	$2.36	29%
TE-C52 & 52A	100UG	$23.72	$30.55	$6.83	29%
	250OH	$12.29	$15.83	$3.54	29%
	250UG	$27.82	$33.86	$6.04	22%
	400OH	$18.70	$24.09	$5.39	29%
	400UG	$34.23	$41.66	$7.43	22%
	55OH	$8.19	$10.55	$2.36	29%
	55P	$8.19	$10.55	$2.36	29%
	55UG	$23.72	$30.55	$6.83	29%
	70UG	$23.72	$30.55	$6.83	29%
	Pole	$2.86	$3.68	$0.82	29%
	Base Power				
	100OH	$1.34	$1.36	$0.02	1%
	100UG	$1.34	$1.36	$0.02	1%
	250OH	$3.36	$3.42	$0.06	2%
	250UG	$3.36	$3.42	$0.06	2%
	400OH	$5.38	$5.47	$0.09	2%
	400UG	$5.38	$5.47	$0.09	2%
	55OH	$0.85	$0.86	$0.01	1%
	55P	$0.85	$0.86	$0.01	1%
	55UG	$0.85	$0.86	$0.01	1%
	70UG	$0.94	$0.96	$0.02	2%

RESIDENTIAL SERVICE RATE R-01

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$15.00	$0.06380	$0.07960	$0.07960		$0.032608	$0.00000			
Small	520	500	20	0		$15.00	$31.90	$1.59	$0.00		$16.96	$0.00	$65.45	$6.10	10.3%
Medium	840	500	340	0		$15.00	$31.90	$27.06	$0.00		$27.39	$0.00	$101.35	$8.86	9.6%
Large	1,250	500	500	250		$15.00	$31.90	$39.80	$19.90		$40.76	$0.00	$147.36	$9.18	6.6%
XLg	1,564	500	500	564		$15.00	$31.90	$39.80	$44.89		$51.00	$0.00	$182.59	$7.85	4.5%
AnnAvg	785	500	285	0		$15.00	$31.90	$22.68	$0.00		$25.60	$0.00	$95.18	$8.40	9.7%
ResAvg	785	500	285	0		$15.00	$31.90	$22.69	$0.00		$25.60	$0.00	$95.19	$8.41	9.7%

RESIDENTIAL SERVICE RATE R-01

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
					$15.00	$0.06380	$0.07960	$0.07960	$0.035691	$0.00000			
Small	822	500	322	0	$15.00	$31.90	$25.63	$0.00	$29.34	$0.00	$101.87	$7.66	8.1%
Medium	1,384	500	500	384	$15.00	$31.90	$39.80	$30.57	$49.40	$0.00	$166.67	$6.30	3.9%
Large	1,997	500	500	997	$15.00	$31.90	$39.80	$79.36	$71.27	$0.00	$237.33	$2.33	1.0%
XLg	2,430	500	500	1,430	$15.00	$31.90	$39.80	$113.83	$86.73	$0.00	$287.26	-$0.44	-0.2%
AnnAvg	785	500	285	0	$15.00	$31.90	$22.68	$0.00	$28.02	$0.00	$97.60	$7.44	8.3%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$41.04	$0.00	$139.68	$7.79	5.9%

RESIDENTIAL SERVICE DEMAND

WINTER

BILL IMPACTS CURRENT R-01 RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	3500	>3500					500	1000	3500	>3500					
										10.00	$0.05620	$0.06520	$0.07810	$0.08710			$0.031532	$0.00682	
Small	0.24	520	500	20	0	0	3.0			10.00	$28.10	$1.30	$0.00	$0.00			$16.40	$3.55	$59.35
Medium	0.28	840	500	340	0	0	4.2			10.00	$28.10	$22.17	$0.00	$0.00			$26.49	$5.73	$92.49
Large	0.31	1,250	500	500	250	0	5.5			10.00	$28.10	$32.60	$19.53	$0.00			$39.42	$8.53	$138.18
XLg	0.33	1,564	500	500	564	0	6.5			10.00	$28.10	$32.60	$44.05	$0.00			$49.32	$10.67	$174.74
AnnAvg	0.27	785	500	285	0	0	4.0			10.00	$28.10	$18.58	$0.00	$0.00			$24.75	$5.35	$86.78
ResAvg	0.27	785	500	285	0	0	4.0			10.00	$28.10	$18.58	$0.00	$0.00			$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW) TIERS		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	1000	>1000			7.0	> 7.0		500	1000	>1000		7.0	> 7.0					
										$12.00	$0.03174	$0.03174	$0.03174		$8.75	$12.50	$0.032608	$0.00000			
																				$ Change	% Change
Small	0.24	520	500	20	0		3.0	3.0	0.0	$12.00	$15.87	$0.63	$0.00		$25.99	$0.00	$16.96	$0.00	$71.45	$12.10	20.4%
Medium	0.28	840	500	340	0		4.2	4.2	0.0	$12.00	$15.87	$10.79	$0.00		$36.49	$0.00	$27.39	$0.00	$102.54	$10.05	10.9%
Large	0.31	1,250	500	500	250		5.5	5.5	0.0	$12.00	$15.87	$15.87	$7.94		$48.21	$0.00	$40.76	$0.00	$140.65	$2.47	1.8%
XLg	0.33	1,564	500	500	564		6.5	6.5	0.0	$12.00	$15.87	$15.87	$17.90		$56.44	$0.00	$51.00	$0.00	$169.08	-$5.66	-3.2%
AnnAvg	0.27	785	500	285	0		4.0	4.0	0.0	$12.00	$15.87	$9.05	$0.00		$34.74	$0.00	$25.60	$0.00	$97.26	$10.48	12.1%
ResAvg	0.27	785	500	285	0		4.0	4.0	0.0	$12.00	$15.87	$9.05	$0.00		$34.74	$0.00	$25.60	$0.00	$97.26	$10.48	12.1%

RESIDENTIAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT R-01 RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	3500	>3500					500	1000	3500	>3500					
										10.00	$0.05620	$0.06720	$0.07980	$0.08820			$0.035111	$0.00682	
Small	0.27	822	500	322	0	0	4.1			10.00	$28.10	$21.64	$0.00	$0.00			$28.86	$5.61	$94.21
Medium	0.32	1,384	500	500	384	0	5.9			10.00	$28.10	$33.60	$30.64	$0.00			$48.59	$9.44	$160.37
Large	0.36	1,997	500	500	997	0	7.7			10.00	$28.10	$33.60	$79.56	$0.00			$70.12	$13.62	$235.00
XLg	0.38	2,430	500	500	1,430	0	8.8			10.00	$28.10	$33.60	$114.11	$0.00			$85.32	$16.57	$287.70
AnnAvg	0.27	785	500	285	0	0	4.0			10.00	$28.10	$19.15	$0.00	$0.00			$27.56	$5.35	$90.16
ResAvg	0.30	1,150	500	500	150	0	5.2			10.00	$28.10	$33.60	$11.97	$0.00			$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS				kW	Delivery (kW) TIERS		Basic Service Charge	Delivery (Energy)				Delivery (Demand)		Base Fuel	PPFAC	Net Bill	$ Change	% Change
			500	1000	>1000			7.0	> 7.0		500	1000	>1000		7.0	> 7.0					
										$12.00	$0.03174	$0.03174	$0.03174		$8.75	$12.50	$0.035691	$0.00000			
Small	0.27	822	500	322	0		4.1	4.1	0.0	$12.00	$15.87	$10.22	$0.00		$35.88	$0.00	$29.34	$0.00	$103.31	$9.10	9.7%
Medium	0.32	1,384	500	500	384		5.9	5.9	0.0	$12.00	$15.87	$15.87	$12.19		$51.80	$0.00	$49.40	$0.00	$157.13	-$3.24	-2.0%
Large	0.36	1,997	500	500	997		7.7	7.0	0.7	$12.00	$15.87	$15.87	$31.64		$61.25	$8.25	$71.27	$0.00	$216.15	-$18.85	-8.0%
XLg	0.38	2,430	500	500	1,430		8.8	7.0	1.8	$12.00	$15.87	$15.87	$45.39		$61.25	$22.38	$86.73	$0.00	$259.49	-$28.21	-9.8%
AnnAvg	0.27	785	500	285	0		4.0	4.0	0.0	$12.00	$15.87	$9.05	$0.00		$34.74	$0.00	$28.02	$0.00	$99.68	$9.52	10.6%
ResAvg	0.30	1,150	500	500	150		5.2	5.2	0.0	$12.00	$15.87	$15.87	$4.76		$45.50	$0.00	$41.04	$0.00	$135.04	$3.15	2.4%

LIFELINE RESIDENTIAL SERVICE RATE R-01LL

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682			
Small	473	473	0	0	0	$10.00	$26.58	$0.00	$0.00	$0.00	$14.91	$3.23	$54.72	$45.72	-16.4%
Medium	740	500	240	0	0	$10.00	$28.10	$15.65	$0.00	$0.00	$23.33	$5.05	$82.13	$73.13	-11.0%
Large	1,071	500	500	71	0	$10.00	$28.10	$32.60	$5.55	$0.00	$33.77	$7.30	$117.32	$108.32	-7.7%
XLg	1,310	500	500	310	0	$10.00	$28.10	$32.60	$24.21	$0.00	$41.31	$8.93	$145.15	$136.15	-6.2%
AnnAvg	662	500	162	0	0	$10.00	$28.10	$10.55	$0.00	$0.00	$20.87	$4.51	$74.03	$65.03	-12.2%
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78	$77.78	-10.4%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06380	$0.07960	$0.07960		$0.032608	$0.00000				
Small	473	473	0	0		$15.00	$30.18	$0.00	$0.00		$15.42	$0.00	$60.60	$45.60	-$0.12	-0.3%
Medium	740	500	240	0		$15.00	$31.90	$19.10	$0.00		$24.13	$0.00	$90.13	$75.13	$2.00	2.7%
Large	1,071	500	500	71		$15.00	$31.90	$39.80	$5.65		$34.92	$0.00	$127.27	$112.27	$3.95	3.6%
XLg	1,310	500	500	310		$15.00	$31.90	$39.80	$24.68		$42.72	$0.00	$154.10	$139.10	$2.95	2.2%
AnnAvg	662	500	162	0		$15.00	$31.90	$12.88	$0.00		$21.58	$0.00	$81.36	$66.36	$1.33	2.0%
ResAvg	785	500	285	0		$15.00	$31.90	$22.69	$0.00		$25.60	$0.00	$95.19	$80.19	$2.41	3.1%

LIFELINE RESIDENTIAL SERVICE RATE R-01LL

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682			
Small	683	500	183	0	0	$10.00	$28.10	$12.30	$0.00	$0.00	$23.98	$4.66	$79.04	$70.04	-11.4%
Medium	1,075	500	500	75	0	$10.00	$28.10	$33.60	$5.99	$0.00	$37.74	$7.33	$122.76	$113.76	-7.3%
Large	1,569	500	500	569	0	$10.00	$28.10	$33.60	$45.41	$0.00	$55.09	$10.70	$182.90	$173.90	-4.9%
XLg	1,880	500	500	880	0	$10.00	$28.10	$33.60	$70.22	$0.00	$66.01	$12.82	$220.75	$211.75	-4.1%
AnnAvg	662	500	162	0	0	$10.00	$28.10	$10.88	$0.00	$0.00	$23.24	$4.51	$76.73	$67.73	-11.7%
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89	$122.89	-6.8%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06380	$0.07960	$0.07960		$0.035691	$0.00000				
Small	683	500	183	0		$15.00	$31.90	$14.57	$0.00		$24.38	$0.00	$85.85	$70.85	$0.81	1.2%
Medium	1,075	500	500	75		$15.00	$31.90	$39.80	$5.97		$38.37	$0.00	$131.04	$116.04	$2.28	2.0%
Large	1,569	500	500	569		$15.00	$31.90	$39.80	$45.29		$56.00	$0.00	$187.99	$172.99	-$0.91	-0.5%
XLg	1,880	500	500	880		$15.00	$31.90	$39.80	$70.05		$67.10	$0.00	$223.85	$208.85	-$2.90	-1.4%
AnnAvg	662	500	162	0		$15.00	$31.90	$12.88	$0.00		$23.62	$0.00	$83.40	$68.40	$0.67	1.0%
ResAvg	1,150	500	500	150		$15.00	$31.90	$39.80	$11.94		$41.04	$0.00	$139.68	$124.68	$1.79	1.5%

LIFELINE SERVICE RATE R-04-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	381	381	0	0	$6.90	$21.72	$0.00	$0.00	$9.79	$2.60	$41.01	$28.71	-30.0%
Medium	604	500	104	0	$6.90	$28.50	$5.93	$0.00	$15.52	$4.12	$60.97	$45.73	-25.0%
Large	913	500	413	0	$6.90	$28.50	$23.54	$0.00	$23.46	$6.23	$88.63	$66.47	-25.0%
XLg	1,197	500	500	197	$6.90	$28.50	$28.50	$11.23	$30.76	$8.16	$114.05	$96.94	-15.0%
AnnAvg	560	500	60	0	$6.90	$28.50	$3.42	$0.00	$14.39	$3.82	$57.03	$39.92	-30.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$57.88	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.032608	$0.00000				
Small	381	381	0	0	$15.00	$24.31	$0.00	$0.00	$12.42	$0.00	$51.73	$21.73	-$6.98	-24.3%
Medium	604	500	104	0	$15.00	$31.90	$8.28	$0.00	$19.70	$0.00	$74.88	$44.88	-$0.85	-1.9%
Large	913	500	413	0	$15.00	$31.90	$32.87	$0.00	$29.77	$0.00	$109.54	$79.54	$13.07	19.7%
XLg	1,197	500	500	197	$15.00	$31.90	$39.80	$15.68	$39.03	$0.00	$141.41	$111.41	$14.47	14.9%
AnnAvg	560	500	60	0	$15.00	$31.90	$4.78	$0.00	$18.26	$0.00	$69.94	$39.94	$0.02	0.1%
ResAvg	785	500	285	0	$15.00	$31.90	$22.69	$0.00	$25.60	$0.00	$95.19	$65.19	$7.31	12.6%

LIFELINE SERVICE RATE R-04-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	552	500	52	0	$6.90	$30.55	$3.18	$0.00	$18.33	$3.76	$62.72	$43.90	-30.0%
Medium	894	500	394	0	$6.90	$30.55	$24.04	$0.00	$29.66	$6.09	$97.24	$72.93	-25.0%
Large	1,280	500	500	280	$6.90	$30.55	$30.55	$17.11	$42.49	$8.73	$136.33	$115.88	-15.0%
XLg	1,550	500	500	550	$6.90	$30.55	$30.55	$33.61	$51.46	$10.57	$163.64	$163.64	0.0%
AnnAvg	560	500	60	0	$6.90	$30.55	$3.67	$0.00	$18.59	$3.82	$63.53	$44.47	-30.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$104.71	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.035691	$0.00000				
Small	552	500	52	0	$15.00	$31.90	$4.14	$0.00	$19.70	$0.00	$70.74	$40.74	-$3.16	-7.2%
Medium	894	500	394	0	$15.00	$31.90	$31.32	$0.00	$31.89	$0.00	$110.11	$80.11	$7.18	9.8%
Large	1,280	500	500	280	$15.00	$31.90	$39.80	$22.29	$45.68	$0.00	$154.67	$124.67	$8.79	7.6%
XLg	1,550	500	500	550	$15.00	$31.90	$39.80	$43.78	$55.32	$0.00	$185.80	$155.80	-$7.84	-4.8%
AnnAvg	560	500	60	0	$15.00	$31.90	$4.78	$0.00	$19.99	$0.00	$71.67	$41.67	-$2.80	-6.3%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$41.04	$0.00	$139.68	$109.68	$4.97	4.7%

LIFELINE SERVICE RATE R-05-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	480	480	0	0	$6.90	$27.36	$0.00	$0.00	$12.34	$3.27	$49.87	$39.90	-20.0%
Medium	719	500	219	0	$6.90	$28.50	$12.48	$0.00	$18.48	$4.90	$71.26	$60.57	-15.0%
Large	1,050	500	500	50	$6.90	$28.50	$28.50	$2.85	$26.98	$7.16	$100.89	$100.89	0.0%
XLg	1,314	500	500	314	$6.90	$28.50	$28.50	$17.90	$33.77	$8.96	$124.53	$124.53	0.0%
AnnAvg	659	500	159	0	$6.90	$28.50	$9.09	$0.00	$16.94	$4.50	$65.93	$56.04	-15.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$65.59	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.032608	$0.00000				
Small	480	480	0	0	$15.00	$30.63	$0.00	$0.00	$15.65	$0.00	$61.28	$46.28	$6.38	16.0%
Medium	719	500	219	0	$15.00	$31.90	$17.43	$0.00	$23.45	$0.00	$87.78	$72.78	$12.21	20.2%
Large	1,050	500	500	50	$15.00	$31.90	$39.80	$3.98	$34.24	$0.00	$124.92	$109.92	$9.03	9.0%
XLg	1,314	500	500	314	$15.00	$31.90	$39.80	$24.99	$42.85	$0.00	$154.54	$139.54	$15.01	12.1%
AnnAvg	659	500	159	0	$15.00	$31.90	$12.69	$0.00	$21.50	$0.00	$81.09	$66.09	$10.05	17.9%
ResAvg	785	500	285	0	$15.00	$31.90	$22.69	$0.00	$25.60	$0.00	$95.19	$80.19	$14.60	22.3%

LIFELINE SERVICE RATE R-05-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	670	500	170	0	$6.90	$30.55	$10.39	$0.00	$22.24	$4.57	$74.65	$63.45	-15.0%
Medium	1,012	500	500	12	$6.90	$30.55	$30.55	$0.70	$33.58	$6.90	$109.18	$109.18	0.0%
Large	1,460	500	500	460	$6.90	$30.55	$30.55	$28.11	$48.47	$9.96	$154.54	$154.54	0.0%
XLg	1,796	500	500	796	$6.90	$30.55	$30.55	$48.64	$59.62	$12.25	$188.51	$188.51	0.0%
AnnAvg	659	500	159	0	$6.90	$30.55	$9.74	$0.00	$21.89	$4.50	$73.58	$62.54	-15.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$123.19	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.035691	$0.00000				
Small	670	500	170	0	$15.00	$31.90	$13.53	$0.00	$23.91	$0.00	$84.34	$69.34	$5.89	9.3%
Medium	1,012	500	500	12	$15.00	$31.90	$39.80	$0.92	$36.10	$0.00	$123.72	$108.72	-$0.46	-0.4%
Large	1,460	500	500	460	$15.00	$31.90	$39.80	$36.62	$52.11	$0.00	$175.43	$160.43	$5.89	3.8%
XLg	1,796	500	500	796	$15.00	$31.90	$39.80	$63.36	$64.10	$0.00	$214.16	$199.16	$10.65	5.6%
AnnAvg	659	500	159	0	$15.00	$31.90	$12.69	$0.00	$23.53	$0.00	$83.12	$68.12	$5.58	8.9%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$41.04	$0.00	$139.68	$124.68	$1.49	1.2%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

WINTER

LIFELINE SERVICE RATE R-06-01 FROZEN

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS 500	1000	>1000	Basic Service Charge	Delivery 500	1000	>1000	Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	490	490	0	0	$6.90	$27.93	$0.00	$0.00	$12.59	$3.34	$50.76	$41.76	-17.7%
Medium	769	500	269	0	$6.90	$28.50	$15.33	$0.00	$19.76	$5.24	$75.73	$66.73	-11.9%
Large	1,127	500	500	127	$6.90	$28.50	$28.50	$7.24	$28.96	$7.69	$107.79	$98.79	-8.3%
XLg	1,400	500	500	400	$6.90	$28.50	$28.50	$22.80	$35.98	$9.55	$132.23	$123.23	-6.8%
AnnAvg	730	500	230	0	$6.90	$28.50	$13.08	$0.00	$18.75	$4.98	$72.21	$63.21	-12.5%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$68.17	-11.7%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS 500	1000	>1000	Basic Service Charge	Delivery 500	1000	>1000	Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
					$15.00	$0.06380	$0.07960	$0.07960	$0.032608	$0.00000				
Small	490	490	0	0	$15.00	$31.26	$0.00	$0.00	$15.98	$0.00	$62.24	$44.24	$2.48	5.9%
Medium	769	500	269	0	$15.00	$31.90	$21.41	$0.00	$25.08	$0.00	$93.39	$75.39	$8.66	13.0%
Large	1,127	500	500	127	$15.00	$31.90	$39.80	$10.11	$36.75	$0.00	$133.56	$115.56	$16.77	17.0%
XLg	1,400	500	500	400	$15.00	$31.90	$39.80	$31.84	$45.65	$0.00	$164.19	$146.19	$22.96	18.6%
AnnAvg	730	500	230	0	$15.00	$31.90	$18.27	$0.00	$23.79	$0.00	$88.96	$70.96	$7.75	12.3%
ResAvg	785	500	285	0	$15.00	$31.90	$22.69	$0.00	$25.60	$0.00	$95.19	$77.19	$9.02	13.2%

LIFELINE SERVICE RATE R-06-01 FROZEN

Summer

	BILL IMPACTS CURRENT RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	758	500	258	0	$6.90	$30.55	$15.76	$0.00	$25.16	$5.17	$83.54	$74.54	-10.8%
Medium	1,220	500	500	220	$6.90	$30.55	$30.55	$13.44	$40.50	$8.32	$130.26	$121.26	-6.9%
Large	1,737	500	500	737	$6.90	$30.55	$30.55	$45.03	$57.66	$11.85	$182.54	$173.54	-4.9%
XLg	2,092	500	500	1,092	$6.90	$30.55	$30.55	$66.72	$69.45	$14.27	$218.44	$209.44	-4.1%
AnnAvg	730	500	230	0	$6.90	$30.55	$14.02	$0.00	$24.22	$4.98	$80.67	$71.67	-11.2%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$114.19	-7.3%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.035691	$0.00000				
Small	758	500	258	0	$15.00	$31.90	$20.54	$0.00	$27.05	$0.00	$94.49	$76.49	$1.95	2.6%
Medium	1,220	500	500	220	$15.00	$31.90	$39.80	$17.51	$43.54	$0.00	$147.75	$129.75	$8.49	7.0%
Large	1,737	500	500	737	$15.00	$31.90	$39.80	$58.67	$62.00	$0.00	$207.37	$189.37	$15.83	9.1%
XLg	2,092	500	500	1,092	$15.00	$31.90	$39.80	$86.92	$74.67	$0.00	$248.29	$230.29	$20.85	10.0%
AnnAvg	730	500	230	0	$15.00	$31.90	$18.27	$0.00	$26.04	$0.00	$91.21	$73.21	$1.54	2.1%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$41.04	$0.00	$139.68	$121.68	$7.49	6.6%

LIFELINE SERVICE RATE R-08-01 FROZEN

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.05700	$0.05700	$0.05700	$0.025698	$0.00682			
Small	688	500	188	0	$6.90	$28.50	$10.72	$0.00	$17.68	$4.69	$68.49	$44.52	-35.0%
Medium	1,016	500	500	16	$6.90	$28.50	$28.50	$0.91	$26.11	$6.93	$97.85	$68.50	-30.0%
Large	1,423	500	500	423	$6.90	$28.50	$28.50	$24.11	$36.57	$9.70	$134.28	$94.00	-30.0%
XLg	1,720	500	500	720	$6.90	$28.50	$28.50	$41.04	$44.20	$11.73	$160.87	$112.61	-30.0%
AnnAvg	974	500	474	0	$6.90	$28.50	$27.04	$0.00	$25.04	$6.64	$94.12	$61.18	-35.0%
ResAvg	785	500	285	0	$6.90	$28.50	$16.25	$0.00	$20.17	$5.35	$77.17	$50.16	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.032608	$0.00000				
Small	688	500	188	0	$15.00	$31.90	$14.96	$0.00	$22.43	$0.00	$84.29	$44.29	-$0.23	-0.5%
Medium	1,016	500	500	16	$15.00	$31.90	$39.80	$1.27	$33.13	$0.00	$121.10	$81.10	$12.60	18.4%
Large	1,423	500	500	423	$15.00	$31.90	$39.80	$33.67	$46.40	$0.00	$166.77	$126.77	$32.77	34.9%
XLg	1,720	500	500	720	$15.00	$31.90	$39.80	$57.31	$56.09	$0.00	$200.10	$160.10	$47.49	42.2%
AnnAvg	974	500	474	0	$15.00	$31.90	$37.76	$0.00	$31.77	$0.00	$116.43	$76.43	$15.25	24.9%
ResAvg	785	500	285	0	$15.00	$31.90	$22.69	$0.00	$25.60	$0.00	$95.19	$55.19	$5.03	10.0%

LIFELINE SERVICE RATE R-08-01 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	1,090	500	500	90	$6.90	$30.55	$30.55	$5.50	$36.19	$7.43	$117.12	$81.98	-30.0%
Medium	1,614	500	500	614	$6.90	$30.55	$30.55	$37.52	$53.58	$11.01	$170.11	$119.08	-30.0%
Large	2,170	500	500	1,170	$6.90	$30.55	$30.55	$71.49	$72.04	$14.80	$226.33	$203.70	-10.0%
XLg	2,511	500	500	1,511	$6.90	$30.55	$30.55	$92.32	$83.36	$17.13	$260.81	$234.73	-10.0%
AnnAvg	974	500	474	0	$6.90	$30.55	$28.98	$0.00	$32.35	$6.64	$105.42	$68.52	-35.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$86.23	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.035691	$0.00000				
Small	1,090	500	500	90	$15.00	$31.90	$39.80	$7.16	$38.90	$0.00	$132.76	$92.76	$10.78	13.1%
Medium	1,614	500	500	614	$15.00	$31.90	$39.80	$48.87	$57.61	$0.00	$193.18	$153.18	$34.10	28.6%
Large	2,170	500	500	1,170	$15.00	$31.90	$39.80	$93.13	$77.45	$0.00	$257.28	$217.28	$13.58	6.7%
XLg	2,511	500	500	1,511	$15.00	$31.90	$39.80	$120.28	$89.62	$0.00	$296.60	$256.60	$21.87	9.3%
AnnAvg	974	500	474	0	$15.00	$31.90	$37.76	$0.00	$34.77	$0.00	$119.43	$79.43	$10.91	15.9%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$41.04	$0.00	$139.68	$99.68	$13.45	15.6%

RESIDENTIAL SERVICE TIME OF USE RATE R-80

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.25				$11.50	$0.05680	$0.05680	$0.05680	$0.032893	$0.00682	
Off-Peak	0.75					$0.04180	$0.04180	$0.04180	$0.027092		
Small	796	500	296	0	$11.50	$22.76	$13.48	$0.00	$22.71	$5.43	$75.88
Medium	1,196	500	500	196	$11.50	$22.76	$22.76	$8.92	$34.13	$8.16	$108.23
Large	1,678	500	500	678	$11.50	$22.76	$22.76	$30.87	$47.88	$11.44	$147.21
XLg	2,047	500	500	1,047	$11.50	$22.76	$22.76	$47.67	$58.41	$13.96	$177.06
AnnAvg	1,125	500	500	125	$11.50	$22.76	$22.76	$5.70	$32.10	$7.67	$102.49
ResAvg	785	500	285	0	$11.50	$22.76	$12.97	$0.00	$22.40	$5.35	$74.98

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000			
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655				
Small	796	500	296	0	$12.00	$31.90	$23.56	$0.00	$21.52	$0.00	$88.98	$13.10	17.3%
Medium	1,196	500	500	196	$12.00	$31.90	$39.80	$15.60	$32.34	$0.00	$131.64	$23.41	21.6%
Large	1,678	500	500	678	$12.00	$31.90	$39.80	$53.97	$45.37	$0.00	$183.04	$35.83	24.3%
XLg	2,047	500	500	1,047	$12.00	$31.90	$39.80	$83.34	$55.35	$0.00	$222.39	$45.33	25.6%
AnnAvg	1,125	500	500	125	$12.00	$31.90	$39.80	$9.96	$30.42	$0.00	$124.08	$21.59	21.1%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$12.83	17.1%

RESIDENTIAL SERVICE TIME OF USE RATE R-80

Summer

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.23					$0.06680	$0.06680	$0.06680	$0.050669	$0.00682	
Off-Peak	0.77					$0.05180	$0.05180	$0.05180	$0.026679		
Small	1,249	500	500	249	$11.50	$27.61	$27.61	$13.72	$40.13	$8.51	$129.08
Medium	1,881	500	500	881	$11.50	$27.61	$27.61	$48.65	$60.46	$12.83	$188.66
Large	2,539	500	500	1,539	$11.50	$27.61	$27.61	$84.98	$81.61	$17.32	$250.63
XLg	3,011	500	500	2,011	$11.50	$27.61	$27.61	$111.04	$96.78	$20.54	$295.08
AnnAvg	1,125	500	500	125	$11.50	$27.61	$27.61	$6.91	$36.16	$7.67	$117.46
ResAvg	1,150	500	500	150	$11.50	$27.61	$27.61	$8.28	$36.96	$7.84	$119.80

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000			
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332			$ Change	% Change
Small	1,249	500	500	249	$12.00	$31.90	$39.80	$19.78	$40.91	$0.00	$144.39	$15.31	11.9%
Medium	1,881	500	500	881	$12.00	$31.90	$39.80	$70.13	$61.64	$0.00	$215.47	$26.81	14.2%
Large	2,539	500	500	1,539	$12.00	$31.90	$39.80	$122.50	$83.20	$0.00	$289.40	$38.77	15.5%
XLg	3,011	500	500	2,011	$12.00	$31.90	$39.80	$160.08	$98.67	$0.00	$342.45	$47.37	16.1%
AnnAvg	1,125	500	500	125	$12.00	$31.90	$39.80	$9.96	$36.87	$0.00	$130.53	$13.07	11.1%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$13.53	11.3%

RESIDENTIAL SERVICE DEMAND TIME OF USE

WINTER

BILL IMPACTS CURRENT R-80 RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW)		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	>1000				$11.50	500	1000	>1000					
On-Peak		0.25								$0.05680	$0.05680	$0.05680			$0.032893	$0.00682	
Off-Peak		0.75								$0.04180	$0.04180	$0.04180			$0.027092		
Small	0.27	796	500	296	0	4.0			$11.50	$22.76	$13.48	$0.00			$22.71	$5.43	$75.88
Medium	0.31	1,196	500	500	196	5.3			$11.50	$22.76	$22.76	$8.92			$34.13	$8.16	$108.23
Large	0.34	1,678	500	500	678	6.8			$11.50	$22.76	$22.76	$30.87			$47.88	$11.44	$147.21
XLg	0.36	2,047	500	500	1,047	7.8			$11.50	$22.76	$22.76	$47.67			$58.41	$13.96	$177.06
AnnAvg	0.30	1,125	500	500	125	5.1			$11.50	$22.76	$22.76	$5.70			$32.10	$7.67	$102.49
ResAvg	0.27	785	500	285	0	4.0			$11.50	$22.76	$12.97	$0.00			$22.40	$5.35	$74.98

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW) TIERS		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	1000	>1000		7.0	> 7.0		500	1000	>1000	7.0	> 7.0					
On-Peak		0.20							$12.00	$0.03174	$0.03174	$0.03174	$8.75	$12.50	$0.032568	$0.00000			
Off-Peak		0.80								$0.03174	$0.03174	$0.03174			$0.025655			$ Change	% Change
Small	0.27	796	500	296	0	4.0	4.0	0.0	$12.00	$15.87	$9.40	$0.00	$35.09	$0.00	$21.52	$0.00	$93.88	$18.00	23.7%
Medium	0.31	1,196	500	500	196	5.3	5.3	0.0	$12.00	$15.87	$15.87	$6.22	$46.73	$0.00	$32.34	$0.00	$129.03	$20.80	19.2%
Large	0.34	1,678	500	500	678	6.8	6.8	0.0	$12.00	$15.87	$15.87	$21.52	$59.33	$0.00	$45.37	$0.00	$169.96	$22.75	15.5%
XLg	0.36	2,047	500	500	1,047	7.8	7.0	0.8	$12.00	$15.87	$15.87	$33.23	$61.25	$9.88	$55.35	$0.00	$203.45	$26.39	14.9%
AnnAvg	0.30	1,125	500	500	125	5.1	5.1	0.0	$12.00	$15.87	$15.87	$3.97	$44.80	$0.00	$30.42	$0.00	$122.93	$20.44	19.9%
ResAvg	0.27	785	500	285	0	4.0	4.0	0.0	$12.00	$15.87	$9.05	$0.00	$34.74	$0.00	$21.22	$0.00	$92.88	$17.90	23.9%

RESIDENTIAL SERVICE DEMAND TIME OF USE

SUMMER

BILL IMPACTS CURRENT R-80 RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW)		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	1000	>1000				$11.50	500	1000	>1000					
On-Peak		0.23								$0.06680	$0.06680	$0.06680			$0.050669	$0.00682	
Off-Peak		0.77								$0.05180	$0.05180	$0.05180			$0.026679		
Small	0.31	1,249	500	500	249	5.5			$11.50	$27.61	$27.61	$13.72			$40.13	$8.51	$129.08
Medium	0.35	1,881	500	500	881	7.3			$11.50	$27.61	$27.61	$48.65			$60.46	$12.83	$188.66
Large	0.38	2,539	500	500	1,539	9.1			$11.50	$27.61	$27.61	$84.98			$81.61	$17.32	$250.63
XLg	0.40	3,011	500	500	2,011	10.2			$11.50	$27.61	$27.61	$111.04			$96.78	$20.54	$295.08
AnnAvg	0.30	1,125	500	500	125	5.1			$11.50	$27.61	$27.61	$6.91			$36.16	$7.67	$117.46
ResAvg	0.30	1,150	500	500	150	5.2			$11.50	$27.61	$27.61	$8.28			$36.96	$7.84	$119.80

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS			kW	Delivery (kW) TIERS		Basic Service Charge	Delivery			Delivery (Demand)		Base Fuel	PPFAC	Net Bill	$ Change	% Change
			500	1000	>1000		7.0	> 7.0		500	1000	>1000	7.0	> 7.0					
On-Peak		0.16							$12.00	$0.03174	$0.03174	$0.03174	$8.75	$12.50	$0.066568	$0.00000			
Off-Peak		0.84								$0.03174	$0.03174	$0.03174			$0.026332				
Small	0.31	1,249	500	500	249	5.5	5.5	0.0	$12.00	$15.87	$15.87	$7.89	$48.21	$0.00	$40.91	$0.00	$140.75	$11.67	9.0%
Medium	0.35	1,881	500	500	881	7.3	7.0	0.3	$12.00	$15.87	$15.87	$27.96	$61.25	$4.25	$61.64	$0.00	$198.84	$10.18	5.4%
Large	0.38	2,539	500	500	1,539	9.1	7.0	2.1	$12.00	$15.87	$15.87	$48.85	$61.25	$25.88	$83.20	$0.00	$262.92	$12.29	4.9%
XLg	0.40	3,011	500	500	2,011	10.2	7.0	3.2	$12.00	$15.87	$15.87	$63.83	$61.25	$40.25	$98.67	$0.00	$307.74	$12.66	4.3%
AnnAvg	0.30	1,125	500	500	125	5.1	5.1	0.0	$12.00	$15.87	$15.87	$3.97	$44.80	$0.00	$36.87	$0.00	$129.38	$11.92	10.1%
ResAvg	0.30	1,150	500	500	150	5.2	5.2	0.0	$12.00	$15.87	$15.87	$4.76	$45.50	$0.00	$37.69	$0.00	$131.69	$11.89	9.9%

LIFELINE RESIDENTIAL SERVICE TIME OF USE RATE R-80L

Winter

	BILL IMPACTS CURRENT RATES												Percentage Discount
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$11.50	$0.05680	$0.05680	$0.05680	$0.032893	$0.00682			
Off-Peak	0.75					$0.04180	$0.04180	$0.04180	$0.027092				
Small	496	496	0	0	$11.50	$22.56	$0.00	$0.00	$14.14	$3.38	$51.58	$42.58	-17.4%
Medium	949	500	449	0	$11.50	$22.76	$20.44	$0.00	$27.08	$6.47	$88.25	$79.25	-10.2%
Large	1,507	500	500	507	$11.50	$22.76	$22.76	$23.08	$43.00	$10.28	$133.38	$124.38	-6.7%
XLg	1,917	500	500	917	$11.50	$22.76	$22.76	$41.75	$54.70	$13.07	$166.54	$157.54	-5.4%
AnnAvg	816	500	316	0	$11.50	$22.76	$14.37	$0.00	$23.27	$5.56	$77.46	$68.46	-11.6%
ResAvg	785	500	285	0	$11.50	$22.76	$12.97	$0.00	$22.40	$5.35	$74.98	$65.98	-12.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655				$ Change	% Change
Small	496	496	0	0	$12.00	$31.61	$0.00	$0.00	$13.40	$0.00	$57.01	$42.01	-$0.57	-1.3%
Medium	949	500	449	0	$12.00	$31.90	$35.74	$0.00	$25.66	$0.00	$105.30	$90.30	$11.05	13.9%
Large	1,507	500	500	507	$12.00	$31.90	$39.80	$40.36	$40.75	$0.00	$164.81	$149.81	$25.43	20.4%
XLg	1,917	500	500	917	$12.00	$31.90	$39.80	$72.99	$51.83	$0.00	$208.52	$193.52	$35.98	22.8%
AnnAvg	816	500	316	0	$12.00	$31.90	$25.13	$0.00	$22.05	$0.00	$91.08	$76.08	$7.62	11.1%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$72.81	$6.83	10.4%

LIFELINE RESIDENTIAL SERVICE TIME OF USE RATE R-80L

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.23					$0.06680	$0.06680	$0.06680	$0.050669	$0.00682			
Off-Peak	0.77					$0.05180	$0.05180	$0.05180	$0.026679				
Small	754	500	254	0	$11.50	$27.61	$14.02	$0.00	$24.24	$5.14	$82.51	$73.51	-10.9%
Medium	1,293	500	500	293	$11.50	$27.61	$27.61	$16.18	$41.56	$8.82	$133.28	$124.28	-6.8%
Large	2,020	500	500	1,020	$11.50	$27.61	$27.61	$56.32	$64.93	$13.78	$201.75	$192.75	-4.5%
XLg	2,353	500	500	1,353	$11.50	$27.61	$27.61	$74.71	$75.63	$16.05	$233.11	$224.11	-3.9%
AnnAvg	816	500	316	0	$11.50	$27.61	$17.43	$0.00	$26.22	$5.56	$88.32	$79.32	-10.2%
ResAvg	1,150	500	500	150	$11.50	$27.61	$27.61	$8.28	$36.96	$7.84	$119.80	$110.80	-7.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	754	500	254	0	$12.00	$31.90	$20.22	$0.00	$24.71	$0.00	$88.83	$73.83	$0.32	0.4%
Medium	1,293	500	500	293	$12.00	$31.90	$39.80	$23.32	$42.37	$0.00	$149.39	$134.39	$10.11	8.1%
Large	2,020	500	500	1,020	$12.00	$31.90	$39.80	$81.19	$66.19	$0.00	$231.08	$216.08	$23.33	12.1%
XLg	2,353	500	500	1,353	$12.00	$31.90	$39.80	$107.70	$77.11	$0.00	$268.51	$253.51	$29.40	13.1%
AnnAvg	816	500	316	0	$12.00	$31.90	$25.13	$0.00	$26.73	$0.00	$95.76	$80.76	$1.44	1.8%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$118.33	$7.53	6.8%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

LIFELINE SERVICE TIME OF USE RATE R-04-21 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.77					$0.03300	$0.03300	$0.03300	$0.020698				
Small	717	500	217	0	$8.86	$20.23	$8.78	$0.00	$18.16	$4.89	$60.92	$45.69	-25.0%
Medium	857	500	357	0	$8.86	$20.23	$14.44	$0.00	$21.71	$5.84	$71.08	$53.31	-25.0%
Large	1,060	500	500	60	$8.86	$20.23	$20.23	$2.43	$26.85	$7.23	$85.83	$72.96	-15.0%
XLg	1,545	500	500	545	$8.86	$20.23	$20.23	$22.05	$39.14	$10.54	$121.05	$121.05	0.0%
AnnAvg	950	500	450	0	$8.86	$20.23	$18.19	$0.00	$24.05	$6.48	$77.81	$58.36	-25.0%
ResAvg	785	500	285	0	$8.86	$20.23	$11.53	$0.00	$19.89	$5.35	$65.86	$49.40	-25.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	717	500	217	0	$12.00	$31.90	$17.27	$0.00	$19.39	$0.00	$80.56	$50.56	$4.87	10.7%
Medium	857	500	357	0	$12.00	$31.90	$28.42	$0.00	$23.17	$0.00	$95.49	$65.49	$12.18	22.8%
Large	1,060	500	500	60	$12.00	$31.90	$39.80	$4.78	$28.66	$0.00	$117.14	$87.14	$14.18	19.4%
XLg	1,545	500	500	545	$12.00	$31.90	$39.80	$43.38	$41.77	$0.00	$168.85	$138.85	$17.80	14.7%
AnnAvg	950	500	450	0	$12.00	$31.90	$35.79	$0.00	$25.67	$0.00	$105.36	$75.36	$17.00	29.1%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$57.81	$8.41	17.0%

LIFELINE SERVICE TIME OF USE RATE R-04-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.37					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.63					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,178	500	500	178	$8.86	$24.17	$24.17	$8.60	$40.56	$8.03	$114.39	$97.23	-15.0%
Medium	1,990	500	500	990	$8.86	$24.17	$24.17	$47.85	$68.52	$13.57	$187.14	$187.14	0.0%
Large	2,154	500	500	1,154	$8.86	$24.17	$24.17	$55.78	$74.17	$14.69	$201.84	$201.84	0.0%
XLg	2,260	500	500	1,260	$8.86	$24.17	$24.17	$60.90	$77.82	$15.41	$211.33	$211.33	0.0%
AnnAvg	950	500	450	0	$8.86	$24.17	$21.73	$0.00	$32.70	$6.48	$93.94	$70.46	-25.0%
ResAvg	1,150	500	500	150	$8.86	$24.17	$24.17	$7.25	$39.60	$7.84	$111.89	$95.11	-15.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	1,178	500	500	178	$12.00	$31.90	$39.80	$14.17	$38.60	$0.00	$136.47	$106.47	$9.24	9.5%
Medium	1,990	500	500	990	$12.00	$31.90	$39.80	$78.80	$65.21	$0.00	$227.71	$197.71	$10.57	5.6%
Large	2,154	500	500	1,154	$12.00	$31.90	$39.80	$91.86	$70.59	$0.00	$246.15	$216.15	$14.31	7.1%
XLg	2,260	500	500	1,260	$12.00	$31.90	$39.80	$100.30	$74.06	$0.00	$258.06	$228.06	$16.73	7.9%
AnnAvg	950	500	450	0	$12.00	$31.90	$35.79	$0.00	$31.12	$0.00	$110.81	$80.81	$10.35	14.7%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$103.33	$8.22	8.6%

LIFELINE SERVICE TIME OF USE RATE R-05-21 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	984	500	484	0	$8.86	$20.51	$19.84	$0.00	$25.26	$6.71	$81.18	$69.00	-15.0%
Medium	1,203	500	500	203	$8.86	$20.51	$20.51	$8.33	$30.90	$8.20	$97.31	$97.31	0.0%
Large	1,447	500	500	447	$8.86	$20.51	$20.51	$18.34	$37.17	$9.87	$115.26	$115.26	0.0%
XLg	1,690	500	500	690	$8.86	$20.51	$20.51	$28.31	$43.41	$11.53	$133.13	$133.13	0.0%
AnnAvg	1,145	500	500	145	$8.86	$20.51	$20.51	$5.93	$29.40	$7.81	$93.02	$93.02	0.0%
ResAvg	785	500	285	0	$8.86	$20.51	$11.69	$0.00	$20.16	$5.35	$66.57	$56.58	-15.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655				$ Change	% Change
Small	984	500	484	0	$12.00	$31.90	$38.49	$0.00	$26.59	$0.00	$108.98	$93.98	$24.98	36.2%
Medium	1,203	500	500	203	$12.00	$31.90	$39.80	$16.16	$32.53	$0.00	$132.39	$117.39	$20.08	20.6%
Large	1,447	500	500	447	$12.00	$31.90	$39.80	$35.58	$39.12	$0.00	$158.40	$143.40	$28.14	24.4%
XLg	1,690	500	500	690	$12.00	$31.90	$39.80	$54.92	$45.69	$0.00	$184.31	$169.31	$36.18	27.2%
AnnAvg	1,145	500	500	145	$12.00	$31.90	$39.80	$11.50	$30.94	$0.00	$126.14	$111.14	$18.12	19.5%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$72.81	$16.23	28.7%

LIFELINE SERVICE TIME OF USE RATE R-05-21 FROZEN

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.38					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.62					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,376	500	500	376	$8.86	$24.24	$24.24	$18.23	$47.50	$9.38	$132.45	$132.45	0.0%
Medium	1,897	500	500	897	$8.86	$24.24	$24.24	$43.49	$65.49	$12.94	$179.26	$179.26	0.0%
Large	2,029	500	500	1,029	$8.86	$24.24	$24.24	$49.89	$70.04	$13.84	$191.11	$191.11	0.0%
XLg	2,029	500	500	1,029	$8.86	$24.24	$24.24	$49.89	$70.04	$13.84	$191.11	$191.11	0.0%
AnnAvg	1,145	500	500	145	$8.86	$24.24	$24.24	$7.01	$39.51	$7.81	$111.67	$111.67	0.0%
ResAvg	1,150	500	500	150	$8.86	$24.24	$24.24	$7.27	$39.70	$7.84	$112.15	$112.15	0.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	1,376	500	500	376	$12.00	$31.90	$39.80	$29.93	$45.09	$0.00	$158.72	$143.72	$11.27	8.5%
Medium	1,897	500	500	897	$12.00	$31.90	$39.80	$71.40	$62.16	$0.00	$217.26	$202.26	$23.00	12.8%
Large	2,029	500	500	1,029	$12.00	$31.90	$39.80	$81.91	$66.49	$0.00	$232.10	$217.10	$25.99	13.6%
XLg	2,029	500	500	1,029	$12.00	$31.90	$39.80	$81.91	$66.49	$0.00	$232.10	$217.10	$25.99	13.6%
AnnAvg	1,145	500	500	145	$12.00	$31.90	$39.80	$11.50	$37.50	$0.00	$132.70	$117.70	$6.03	5.4%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$118.33	$6.18	5.5%

LIFELINE SERVICE TIME OF USE RATE R-06-21 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	811	500	311	0	$8.86	$20.51	$12.76	$0.00	$20.82	$5.53	$68.48	$59.48	-13.1%
Medium	1,159	500	500	159	$8.86	$20.51	$20.51	$6.52	$29.76	$7.90	$94.06	$85.06	-9.6%
Large	1,610	500	500	610	$8.86	$20.51	$20.51	$25.02	$41.34	$10.98	$127.22	$118.22	-7.1%
XLg	2,299	500	500	1,299	$8.86	$20.51	$20.51	$53.28	$59.03	$15.68	$177.87	$168.87	-5.1%
AnnAvg	1,151	500	500	151	$8.86	$20.51	$20.51	$6.21	$29.56	$7.85	$93.50	$84.50	-9.6%
ResAvg	785	500	285	0	$8.86	$20.51	$11.69	$0.00	$20.16	$5.35	$66.57	$57.57	-13.5%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	811	500	311	0	$12.00	$31.90	$24.76	$0.00	$21.93	$0.00	$90.59	$72.59	$13.11	22.0%
Medium	1,159	500	500	159	$12.00	$31.90	$39.80	$12.66	$31.34	$0.00	$127.70	$109.70	$24.64	29.0%
Large	1,610	500	500	610	$12.00	$31.90	$39.80	$48.56	$43.53	$0.00	$175.79	$157.79	$39.57	33.5%
XLg	2,299	500	500	1,299	$12.00	$31.90	$39.80	$103.40	$62.16	$0.00	$249.26	$231.26	$62.39	36.9%
AnnAvg	1,151	500	500	151	$12.00	$31.90	$39.80	$12.05	$31.13	$0.00	$126.88	$108.88	$24.38	28.9%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$69.81	$12.24	21.3%

LIFELINE SERVICE TIME OF USE RATE R-06-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.34					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.66					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,065	500	500	65	$8.86	$23.29	$23.29	$3.03	$35.52	$7.26	$101.25	$92.25	-8.9%
Medium	1,606	500	500	606	$8.86	$23.29	$23.29	$28.23	$53.56	$10.95	$148.18	$139.18	-6.1%
Large	2,060	500	500	1,060	$8.86	$23.29	$23.29	$49.38	$68.70	$14.05	$187.57	$178.57	-4.8%
XLg	2,900	500	500	1,900	$8.86	$23.29	$23.29	$88.50	$96.72	$19.78	$260.44	$251.44	-3.5%
AnnAvg	1,151	500	500	151	$8.86	$23.29	$23.29	$7.05	$38.40	$7.85	$108.74	$99.74	-8.3%
ResAvg	1,150	500	500	150	$8.86	$23.29	$23.29	$6.99	$38.35	$7.84	$108.62	$99.62	-8.3%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	1,065	500	500	65	$12.00	$31.90	$39.80	$5.17	$34.90	$0.00	$123.77	$105.77	$13.52	14.7%
Medium	1,606	500	500	606	$12.00	$31.90	$39.80	$48.24	$52.63	$0.00	$184.57	$166.57	$27.39	19.7%
Large	2,060	500	500	1,060	$12.00	$31.90	$39.80	$84.38	$67.51	$0.00	$235.59	$217.59	$39.02	21.9%
XLg	2,900	500	500	1,900	$12.00	$31.90	$39.80	$151.24	$95.03	$0.00	$329.97	$311.97	$60.53	24.1%
AnnAvg	1,151	500	500	151	$12.00	$31.90	$39.80	$12.05	$37.73	$0.00	$133.48	$115.48	$15.74	15.8%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$115.33	$15.71	15.8%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

LIFELINE SERVICE TIME OF USE RATE R-08-21 FROZEN

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.25				$8.86	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Off-Peak	0.75					$0.03300	$0.03300	$0.03300	$0.020698				
Small	1,070	500	500	70	$8.86	$20.45	$20.45	$2.86	$27.39	$7.30	$87.31	$61.12	-30.0%
Medium	1,285	500	500	285	$8.86	$20.45	$20.45	$11.66	$32.90	$8.76	$103.08	$72.16	-30.0%
Large	1,891	500	500	891	$8.86	$20.45	$20.45	$36.44	$48.41	$12.90	$147.51	$103.26	-30.0%
XLg	2,480	500	500	1,480	$8.86	$20.45	$20.45	$60.53	$63.49	$16.91	$190.69	$171.62	-10.0%
AnnAvg	1,485	500	500	485	$8.86	$20.45	$20.45	$19.85	$38.03	$10.13	$117.77	$82.44	-30.0%
ResAvg	785	500	285	0	$8.86	$20.45	$11.66	$0.00	$20.10	$5.35	$66.42	$43.17	-35.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	1,070	500	500	70	$12.00	$31.90	$39.80	$5.57	$28.93	$0.00	$118.20	$78.20	$17.08	27.9%
Medium	1,285	500	500	285	$12.00	$31.90	$39.80	$22.69	$34.74	$0.00	$141.13	$101.13	$28.97	40.1%
Large	1,891	500	500	891	$12.00	$31.90	$39.80	$70.92	$51.13	$0.00	$205.75	$165.75	$62.49	60.5%
XLg	2,480	500	500	1,480	$12.00	$31.90	$39.80	$117.81	$67.05	$0.00	$268.56	$228.56	$56.94	33.2%
AnnAvg	1,485	500	500	485	$12.00	$31.90	$39.80	$38.63	$40.16	$0.00	$162.49	$122.49	$40.05	48.6%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$47.81	$4.64	10.7%

LIFELINE SERVICE TIME OF USE RATE R-08-21 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$8.86	500	1000	>1000					
On-Peak	0.36					$0.07880	$0.07880	$0.07880	$0.053198	$0.00682			
Off-Peak	0.64					$0.03010	$0.03010	$0.03010	$0.023198				
Small	1,430	500	500	430	$8.86	$23.85	$23.85	$20.51	$48.67	$9.75	$135.49	$94.84	-30.0%
Medium	2,071	500	500	1,071	$8.86	$23.85	$23.85	$51.08	$70.49	$14.12	$192.25	$173.03	-10.0%
Large	3,995	500	500	2,995	$8.86	$23.85	$23.85	$142.84	$135.97	$27.25	$362.62	$326.36	-10.0%
XLg	4,939	500	500	3,939	$8.86	$23.85	$23.85	$187.86	$168.10	$33.68	$446.20	$401.58	-10.0%
AnnAvg	1,485	500	500	485	$8.86	$23.85	$23.85	$23.14	$50.55	$10.13	$140.38	$98.27	-30.0%
ResAvg	1,150	500	500	150	$8.86	$23.85	$23.85	$7.15	$39.14	$7.84	$110.69	$77.48	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	1,430	500	500	430	$12.00	$31.90	$39.80	$34.23	$46.86	$0.00	$164.79	$124.79	$29.95	31.6%
Medium	2,071	500	500	1,071	$12.00	$31.90	$39.80	$85.25	$67.87	$0.00	$236.82	$196.82	$23.79	13.7%
Large	3,995	500	500	2,995	$12.00	$31.90	$39.80	$238.40	$130.92	$0.00	$453.02	$413.02	$86.66	26.6%
XLg	4,939	500	500	3,939	$12.00	$31.90	$39.80	$313.54	$161.85	$0.00	$559.09	$519.09	$117.51	29.3%
AnnAvg	1,485	500	500	485	$12.00	$31.90	$39.80	$38.63	$48.67	$0.00	$171.00	$131.00	$32.73	33.3%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$93.33	$15.85	20.5%

LIFELINE SERVICE TIME OF USE RATE R-04-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.23				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.77					$0.02490	$0.02490	$0.02490	$0.020698				
Small	538	500	38	0	$8.78	$20.12	$1.51	$0.00	$13.57	$3.67	$47.65	$33.36	-30.0%
Medium	850	500	350	0	$8.78	$20.12	$14.09	$0.00	$21.45	$5.80	$70.24	$52.68	-25.0%
Large	1,402	500	500	402	$8.78	$20.12	$20.12	$16.18	$35.38	$9.56	$110.14	$93.62	-15.0%
XLg	1,734	500	500	734	$8.78	$20.12	$20.12	$29.54	$43.76	$11.83	$134.15	$134.15	0.0%
AnnAvg	831	500	331	0	$8.78	$20.12	$13.34	$0.00	$20.98	$5.67	$68.89	$51.67	-25.0%
ResAvg	785	500	285	0	$8.78	$20.12	$11.47	$0.00	$19.81	$5.35	$65.53	$49.15	-25.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	538	500	38	0	$12.00	$31.90	$2.99	$0.00	$14.53	$0.00	$61.42	$31.42	-$1.94	-5.8%
Medium	850	500	350	0	$12.00	$31.90	$27.86	$0.00	$22.98	$0.00	$94.74	$64.74	$12.06	22.9%
Large	1,402	500	500	402	$12.00	$31.90	$39.80	$32.00	$37.91	$0.00	$153.61	$123.61	$29.99	32.0%
XLg	1,734	500	500	734	$12.00	$31.90	$39.80	$58.43	$46.88	$0.00	$189.01	$159.01	$24.86	18.5%
AnnAvg	831	500	331	0	$12.00	$31.90	$26.38	$0.00	$22.48	$0.00	$92.76	$62.76	$11.09	21.5%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$57.81	$8.66	17.6%

LIFELINE SERVICE TIME OF USE RATE R-04-70 FROZEN

Summer

	BILL IMPACTS CURRENT RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.22				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Peak	0.07					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.71					$0.03790	$0.03790	$0.03790	$0.023198				
Small	866	500	366	0	$8.78	$31.40	$22.95	$0.00	$27.85	$5.90	$96.88	$72.66	-25.0%
Medium	1,170	500	500	170	$8.78	$31.40	$31.40	$10.68	$37.64	$7.98	$127.88	$108.70	-15.0%
Large	1,910	500	500	910	$8.78	$31.40	$31.40	$57.15	$61.45	$13.03	$203.21	$203.21	0.0%
XLg	2,469	500	500	1,469	$8.78	$31.40	$31.40	$92.25	$79.43	$16.84	$260.10	$260.10	0.0%
AnnAvg	831	500	331	0	$8.78	$31.40	$20.81	$0.00	$26.75	$5.67	$93.41	$70.06	-25.0%
ResAvg	1,150	500	500	150	$8.78	$31.40	$31.40	$9.42	$37.00	$7.84	$125.84	$106.96	-15.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332				$ Change	% Change
Small	866	500	366	0	$12.00	$31.90	$29.09	$0.00	$28.36	$0.00	$101.35	$71.35	-$1.31	-1.8%
Medium	1,170	500	500	170	$12.00	$31.90	$39.80	$13.53	$38.34	$0.00	$135.57	$105.57	-$3.13	-2.9%
Large	1,910	500	500	910	$12.00	$31.90	$39.80	$72.44	$62.59	$0.00	$218.73	$188.73	-$14.48	-7.1%
XLg	2,469	500	500	1,469	$12.00	$31.90	$39.80	$116.93	$80.91	$0.00	$281.54	$251.54	-$8.56	-3.3%
AnnAvg	831	500	331	0	$12.00	$31.90	$26.38	$0.00	$27.25	$0.00	$97.53	$67.53	-$2.53	-3.6%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$103.33	-$3.63	-3.4%

LIFELINE SERVICE TIME OF USE RATE R-05-70 FROZEN

Winter

	BILL IMPACTS CURRENT RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		Percentage Discount
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682				
Shoulder-Peak	n/a													
Off-Peak	0.80					$0.02490	$0.02490	$0.02490	$0.020698					
Small	428	428	0	0	$8.78	$16.49	$0.00	$0.00	$10.58	$2.92	$38.77	$31.02		-20.0%
Medium	776	500	276	0	$8.78	$19.26	$10.63	$0.00	$19.19	$5.29	$63.15	$53.68		-15.0%
Large	1,220	500	500	220	$8.78	$19.26	$19.26	$8.48	$30.17	$8.32	$94.27	$94.27		0.0%
XLg	1,267	500	500	267	$8.78	$19.26	$19.26	$10.29	$31.33	$8.64	$97.56	$97.56		0.0%
AnnAvg	684	500	184	0	$8.78	$19.26	$7.09	$0.00	$16.91	$4.66	$56.70	$48.20		-15.0%
ResAvg	785	500	285	0	$8.78	$19.26	$10.98	$0.00	$19.41	$5.35	$63.78	$54.21		-15.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655				$ Change	% Change
Small	428	428	0	0	$12.00	$27.31	$0.00	$0.00	$11.57	$0.00	$50.88	$35.88	$4.86	15.7%
Medium	776	500	276	0	$12.00	$31.90	$21.97	$0.00	$20.98	$0.00	$86.85	$71.85	$18.17	33.8%
Large	1,220	500	500	220	$12.00	$31.90	$39.80	$17.51	$32.99	$0.00	$134.20	$119.20	$24.93	26.4%
XLg	1,267	500	500	267	$12.00	$31.90	$39.80	$21.25	$34.26	$0.00	$139.21	$124.21	$26.65	27.3%
AnnAvg	684	500	184	0	$12.00	$31.90	$14.64	$0.00	$18.49	$0.00	$77.03	$62.03	$13.83	28.7%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$72.81	$18.60	34.3%

LIFELINE SERVICE TIME OF USE RATE R-05-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Pea	0.08					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.72					$0.03790	$0.03790	$0.03790	$0.023198				
Small	752	500	252	0	$8.78	$30.66	$15.42	$0.00	$23.88	$5.13	$83.87	$71.29	-15.0%
Medium	1,203	500	500	203	$8.78	$30.66	$30.66	$12.42	$38.22	$8.20	$128.94	$128.94	0.0%
Large	1,647	500	500	647	$8.78	$30.66	$30.66	$39.68	$52.35	$11.23	$173.36	$173.36	0.0%
XLg	1,935	500	500	935	$8.78	$30.66	$30.66	$57.34	$61.50	$13.20	$202.14	$202.14	0.0%
AnnAvg	684	500	184	0	$8.78	$30.66	$11.28	$0.00	$21.74	$4.66	$77.12	$65.55	-15.0%
ResAvg	1,150	500	500	150	$8.78	$30.66	$30.66	$9.20	$36.55	$7.84	$123.69	$123.69	0.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	752	500	252	0	$12.00	$31.90	$20.02	$0.00	$24.63	$0.00	$88.55	$73.55	$2.26	3.2%
Medium	1,203	500	500	203	$12.00	$31.90	$39.80	$16.12	$39.41	$0.00	$139.23	$124.23	-$4.71	-3.7%
Large	1,647	500	500	647	$12.00	$31.90	$39.80	$51.50	$53.97	$0.00	$189.17	$174.17	$0.81	0.5%
XLg	1,935	500	500	935	$12.00	$31.90	$39.80	$74.43	$63.41	$0.00	$221.54	$206.54	$4.40	2.2%
AnnAvg	684	500	184	0	$12.00	$31.90	$14.64	$0.00	$22.41	$0.00	$80.95	$65.95	$0.40	0.6%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$118.33	-$5.36	-4.3%

LIFELINE SERVICE TIME OF USE RATE R-06-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS 500	Delivery (kWh) TIERS 1000	Delivery (kWh) TIERS >1000	Basic Service Charge	Delivery 500	Delivery 1000	Delivery >1000	Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
On-Peak	0.23				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.77					$0.02490	$0.02490	$0.02490	$0.020698				
Small	664	500	164	0	$8.78	$20.14	$6.60	$0.00	$16.76	$4.53	$56.81	$47.81	-15.8%
Medium	1,011	500	500	11	$8.78	$20.14	$20.14	$0.44	$25.52	$6.90	$81.92	$72.92	-11.0%
Large	1,395	500	500	395	$8.78	$20.14	$20.14	$15.91	$35.22	$9.51	$109.70	$100.70	-8.2%
XLg	1,744	500	500	744	$8.78	$20.14	$20.14	$29.96	$44.03	$11.89	$134.94	$125.94	-6.7%
AnnAvg	933	500	433	0	$8.78	$20.14	$17.43	$0.00	$23.55	$6.36	$76.26	$67.26	-11.8%
ResAvg	785	500	285	0	$8.78	$20.14	$11.48	$0.00	$19.82	$5.35	$65.57	$56.57	-13.7%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS 500	Delivery (kWh) TIERS 1000	Delivery (kWh) TIERS >1000	Basic Service Charge	Delivery 500	Delivery 1000	Delivery >1000	Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	664	500	164	0	$12.00	$31.90	$13.05	$0.00	$17.95	$0.00	$74.90	$59.90	$12.09	25.3%
Medium	1,011	500	500	11	$12.00	$31.90	$39.80	$0.88	$27.33	$0.00	$111.91	$96.91	$23.99	32.9%
Large	1,395	500	500	395	$12.00	$31.90	$39.80	$31.44	$37.72	$0.00	$152.86	$137.86	$37.16	36.9%
XLg	1,744	500	500	744	$12.00	$31.90	$39.80	$59.22	$47.15	$0.00	$190.07	$175.07	$49.13	39.0%
AnnAvg	933	500	433	0	$12.00	$31.90	$34.45	$0.00	$25.22	$0.00	$103.57	$88.57	$21.31	31.7%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$72.81	$16.24	28.7%

LIFELINE SERVICE TIME OF USE RATE R-06-70 FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Pea	0.09					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.71					$0.03790	$0.03790	$0.03790	$0.023198				
Small	971	500	471	0	$8.78	$30.93	$29.10	$0.00	$31.12	$6.62	$106.55	$97.55	-8.4%
Medium	1,577	500	500	577	$8.78	$30.93	$30.93	$35.69	$50.57	$10.76	$167.66	$158.66	-5.4%
Large	2,196	500	500	1,196	$8.78	$30.93	$30.93	$73.97	$70.42	$14.98	$230.01	$221.01	-3.9%
XLg	2,503	500	500	1,503	$8.78	$30.93	$30.93	$92.96	$80.27	$17.07	$260.94	$251.94	-3.4%
AnnAvg	933	500	433	0	$8.78	$30.93	$26.77	$0.00	$29.92	$6.36	$102.76	$93.76	-8.8%
ResAvg	1,150	500	500	150	$8.78	$30.93	$30.93	$9.28	$36.88	$7.84	$124.64	$115.64	-7.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	971	500	471	0	$12.00	$31.90	$37.45	$0.00	$31.80	$0.00	$113.15	$98.15	$0.60	0.6%
Medium	1,577	500	500	577	$12.00	$31.90	$39.80	$45.93	$51.68	$0.00	$181.31	$166.31	$7.65	4.8%
Large	2,196	500	500	1,196	$12.00	$31.90	$39.80	$95.20	$71.96	$0.00	$250.86	$235.86	$14.85	6.7%
XLg	2,503	500	500	1,503	$12.00	$31.90	$39.80	$119.64	$82.02	$0.00	$285.36	$270.36	$18.42	7.3%
AnnAvg	933	500	433	0	$12.00	$31.90	$34.45	$0.00	$30.57	$0.00	$108.92	$93.92	$0.16	0.2%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$118.33	$2.69	2.3%

LIFELINE SERVICE TIME OF USE RATE R-08-70 FROZEN

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.22				$8.78	$0.09250	$0.09250	$0.09250	$0.040698	$0.00682			
Shoulder-Peak	n/a												
Off-Peak	0.78					$0.02490	$0.02490	$0.02490	$0.020698				
Small	770	500	270	0	$8.78	$19.74	$10.66	$0.00	$19.26	$5.25	$63.69	$41.40	-35.0%
Medium	980	500	480	0	$8.78	$19.74	$18.95	$0.00	$24.51	$6.68	$78.66	$51.13	-35.0%
Large	1,312	500	500	312	$8.78	$19.74	$19.74	$12.32	$32.81	$8.95	$102.34	$71.64	-30.0%
XLg	1,636	500	500	636	$8.78	$19.74	$19.74	$25.11	$40.92	$11.16	$125.45	$87.82	-30.0%
AnnAvg	994	500	494	0	$8.78	$19.74	$19.49	$0.00	$24.85	$6.78	$79.64	$51.77	-35.0%
ResAvg	785	500	285	0	$8.78	$19.74	$11.25	$0.00	$19.63	$5.35	$64.75	$42.09	-35.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	770	500	270	0	$12.00	$31.90	$21.49	$0.00	$20.82	$0.00	$86.21	$46.21	$4.81	11.6%
Medium	980	500	480	0	$12.00	$31.90	$38.21	$0.00	$26.50	$0.00	$108.61	$68.61	$17.48	34.2%
Large	1,312	500	500	312	$12.00	$31.90	$39.80	$24.84	$35.47	$0.00	$144.01	$104.01	$32.37	45.2%
XLg	1,636	500	500	636	$12.00	$31.90	$39.80	$50.63	$44.23	$0.00	$178.56	$138.56	$50.74	57.8%
AnnAvg	994	500	494	0	$12.00	$31.90	$39.30	$0.00	$26.87	$0.00	$110.07	$70.07	$18.30	35.3%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$47.81	$5.72	13.6%

LIFELINE SERVICE TIME OF USE RATE R-08-70 FROZEN

Summer

	BILL IMPACTS CURRENT RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$8.78	$0.13930	$0.13930	$0.13930	$0.055698	$0.00682			
Shoulder-Pea	0.08					$0.07400	$0.07400	$0.07400	$0.048198				
Off-Peak	0.72					$0.03790	$0.03790	$0.03790	$0.023198				
Small	1,206	500	500	206	$8.78	$30.44	$30.44	$12.51	$38.18	$8.22	$128.57	$90.00	-30.0%
Medium	1,820	500	500	820	$8.78	$30.44	$30.44	$49.93	$57.65	$12.41	$189.65	$132.76	-30.0%
Large	2,139	500	500	1,139	$8.78	$30.44	$30.44	$69.35	$67.75	$14.59	$221.35	$199.22	-10.0%
XLg	2,382	500	500	1,382	$8.78	$30.44	$30.44	$84.14	$75.45	$16.25	$245.50	$220.95	-10.0%
AnnAvg	994	500	494	0	$8.78	$30.44	$30.06	$0.00	$31.48	$6.78	$107.54	$69.90	-35.0%
ResAvg	1,150	500	500	150	$8.78	$30.44	$30.44	$9.13	$36.43	$7.84	$123.06	$86.14	-30.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	1,206	500	500	206	$12.00	$31.90	$39.80	$16.36	$39.50	$0.00	$139.56	$99.56	$9.56	10.6%
Medium	1,820	500	500	820	$12.00	$31.90	$39.80	$65.27	$59.64	$0.00	$208.61	$168.61	$35.85	27.0%
Large	2,139	500	500	1,139	$12.00	$31.90	$39.80	$90.66	$70.09	$0.00	$244.45	$204.45	$5.23	2.6%
XLg	2,382	500	500	1,382	$12.00	$31.90	$39.80	$110.01	$78.06	$0.00	$271.77	$231.77	$10.82	4.9%
AnnAvg	994	500	494	0	$12.00	$31.90	$39.30	$0.00	$32.56	$0.00	$115.76	$75.76	$5.86	8.4%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$93.33	$7.19	8.3%

RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.11				$11.50	$0.08910	$0.08910	$0.11210	$0.040200	$0.00682	
Off-Peak	0.89					$0.03850	$0.03850	$0.06150	$0.020500		
Small	557	500	57	0	$11.50	$22.05	$2.51	$0.00	$12.63	$3.80	$52.49
Medium	876	500	376	0	$11.50	$22.05	$16.56	$0.00	$19.85	$5.97	$75.93
Large	1,370	500	500	370	$11.50	$22.05	$22.05	$24.82	$31.07	$9.34	$120.83
XLg	1,715	500	500	715	$11.50	$22.05	$22.05	$47.97	$38.89	$11.70	$154.16
AnnAvg	769	500	269	0	$11.50	$22.05	$11.86	$0.00	$17.44	$5.24	$68.09
ResAvg	785	500	285	0	$11.50	$22.05	$12.57	$0.00	$17.80	$5.35	$69.27

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000			
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655				
Small	557	500	57	0	$12.00	$31.90	$4.54	$0.00	$15.06	$0.00	$63.50	$11.01	21.0%
Medium	876	500	376	0	$12.00	$31.90	$29.89	$0.00	$23.67	$0.00	$97.46	$21.53	28.4%
Large	1,370	500	500	370	$12.00	$31.90	$39.80	$29.45	$37.04	$0.00	$150.19	$29.36	24.3%
XLg	1,715	500	500	715	$12.00	$31.90	$39.80	$56.91	$46.37	$0.00	$186.98	$32.82	21.3%
AnnAvg	769	500	269	0	$12.00	$31.90	$21.40	$0.00	$20.79	$0.00	$86.09	$18.00	26.4%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$18.54	26.8%

RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8

Summer

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.13					$0.09710	$0.09710	$0.12010	$0.080100	$0.00682	
Off-Peak	0.87					$0.04850	$0.04850	$0.07150	$0.022200		
Small	728	500	228	0	$11.50	$27.39	$12.46	$0.00	$21.59	$4.96	$77.90
Medium	1,222	500	500	222	$11.50	$27.39	$27.39	$17.27	$36.26	$8.33	$128.14
Large	1,666	500	500	666	$11.50	$27.39	$27.39	$51.80	$49.44	$11.36	$178.88
XLg	2,219	500	500	1,219	$11.50	$27.39	$27.39	$94.81	$65.85	$15.13	$242.07
AnnAvg	769	500	269	0	$11.50	$27.39	$14.73	$0.00	$22.82	$5.24	$81.68
ResAvg	1,150	500	500	150	$11.50	$27.39	$27.39	$11.67	$34.13	$7.84	$119.92

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000			
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332			$ Change	% Change
Small	728	500	228	0	$12.00	$31.90	$18.11	$0.00	$23.84	$0.00	$85.85	$7.95	10.2%
Medium	1,222	500	500	222	$12.00	$31.90	$39.80	$17.67	$40.04	$0.00	$141.41	$13.27	10.4%
Large	1,666	500	500	666	$12.00	$31.90	$39.80	$53.01	$54.59	$0.00	$191.30	$12.42	6.9%
XLg	2,219	500	500	1,219	$12.00	$31.90	$39.80	$97.03	$72.72	$0.00	$253.45	$11.38	4.7%
AnnAvg	769	500	269	0	$12.00	$31.90	$21.40	$0.00	$25.20	$0.00	$90.50	$8.82	10.8%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$13.41	11.2%

LIFELINE RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8L

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.11				$11.50	$0.08910	$0.08910	$0.11210	$0.040200	$0.00682			
Off-Peak	0.89					$0.03850	$0.03850	$0.06150	$0.020500				
Small	461	461	0	0	$11.50	$20.33	$0.00	$0.00	$10.45	$3.14	$45.42	$36.42	-19.8%
Medium	835	500	335	0	$11.50	$22.05	$14.77	$0.00	$18.94	$5.69	$72.95	$63.95	-12.3%
Large	946	500	446	0	$11.50	$22.05	$19.66	$0.00	$21.45	$6.45	$81.11	$72.11	-11.1%
XLg	980	500	480	0	$11.50	$22.05	$21.16	$0.00	$22.22	$6.68	$83.61	$74.61	-10.8%
AnnAvg	729	500	229	0	$11.50	$22.05	$10.11	$0.00	$16.54	$4.97	$65.17	$56.17	-13.8%
ResAvg	785	500	285	0	$11.50	$22.05	$12.57	$0.00	$17.80	$5.35	$69.27	$60.27	-13.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.032568	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.025655					
Small	461	461	0	0	$12.00	$29.41	$0.00	$0.00	$12.46	$0.00	$53.87	$38.87	$2.45	6.7%
Medium	835	500	335	0	$12.00	$31.90	$26.67	$0.00	$22.58	$0.00	$93.15	$78.15	$14.20	22.2%
Large	946	500	446	0	$12.00	$31.90	$35.50	$0.00	$25.58	$0.00	$104.98	$89.98	$17.87	24.8%
XLg	980	500	480	0	$12.00	$31.90	$38.21	$0.00	$26.50	$0.00	$108.61	$93.61	$19.00	25.5%
AnnAvg	729	500	229	0	$12.00	$31.90	$18.25	$0.00	$19.72	$0.00	$81.87	$66.87	$10.70	19.0%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$21.22	$0.00	$87.81	$72.81	$12.54	20.8%

LIFELINE RESIDENTIAL SERVICE TIME OF USE SUPER-PEAK RATE R-8L

Summer

	BILL IMPACTS CURRENT RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.13					$0.09710	$0.09710	$0.12010	$0.080100	$0.00682			
Off-Peak	0.87					$0.04850	$0.04850	$0.07150	$0.022200				
Small	1,305	500	500	305	$11.50	$27.39	$27.39	$23.72	$38.73	$8.90	$137.63	$128.63	-6.5%
Medium	1,464	500	500	464	$11.50	$27.39	$27.39	$36.09	$43.44	$9.98	$155.79	$146.79	-5.8%
Large	1,559	500	500	559	$11.50	$27.39	$27.39	$43.48	$46.26	$10.63	$166.65	$157.65	-5.4%
XLg	1,559	500	500	559	$11.50	$27.39	$27.39	$43.48	$46.26	$10.63	$166.65	$157.65	-5.4%
AnnAvg	729	500	229	0	$11.50	$27.39	$12.56	$0.00	$21.64	$4.97	$78.06	$69.06	-11.5%
ResAvg	1,150	500	500	150	$11.50	$27.39	$27.39	$11.67	$34.13	$7.84	$119.92	$110.92	-7.5%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.066568	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.026332					
Small	1,305	500	500	305	$12.00	$31.90	$39.80	$24.28	$42.76	$0.00	$150.74	$135.74	$7.11	5.5%
Medium	1,464	500	500	464	$12.00	$31.90	$39.80	$36.93	$47.97	$0.00	$168.60	$153.60	$6.81	4.6%
Large	1,559	500	500	559	$12.00	$31.90	$39.80	$44.50	$51.09	$0.00	$179.29	$164.29	$6.64	4.2%
XLg	1,559	500	500	559	$12.00	$31.90	$39.80	$44.50	$51.09	$0.00	$179.29	$164.29	$6.64	4.2%
AnnAvg	729	500	229	0	$12.00	$31.90	$18.25	$0.00	$23.90	$0.00	$86.05	$71.05	$1.99	2.9%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$37.69	$0.00	$133.33	$118.33	$7.41	6.7%

SPECIAL RESIDENTIAL ELECTRIC SERVICE RATE R-201A

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05060	$0.05870	$0.07030	$0.07840	$0.031532	$0.00682	
Small	759	500	259	0	0	$10.00	$25.30	$15.20	$0.00	$0.00	$23.93	$5.18	$79.61
Medium	1,110	500	500	110	0	$10.00	$25.30	$29.35	$7.73	$0.00	$35.00	$7.57	$114.95
Large	1,513	500	500	513	0	$10.00	$25.30	$29.35	$36.06	$0.00	$47.71	$10.32	$158.74
XLg	1,820	500	500	820	0	$10.00	$25.30	$29.35	$57.65	$0.00	$57.39	$12.41	$192.10
AnnAvg	946	500	446	0	0	$10.00	$25.30	$26.17	$0.00	$0.00	$29.82	$6.45	$97.74
ResAvg	785	500	285	0	0	$10.00	$25.30	$16.73	$0.00	$0.00	$24.75	$5.35	$82.13

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$15.00	$0.06380	$0.07960	$0.07960		$0.026086	$0.00000			
Small	759	500	259	0		$15.00	$31.90	$20.62	$0.00		$19.80	$0.00	$87.32	$7.71	9.7%
Medium	1,110	500	500	110		$15.00	$31.90	$39.80	$8.76		$28.96	$0.00	$124.42	$9.47	8.2%
Large	1,513	500	500	513		$15.00	$31.90	$39.80	$40.83		$39.47	$0.00	$167.00	$8.26	5.2%
XLg	1,820	500	500	820		$15.00	$31.90	$39.80	$65.27		$47.48	$0.00	$199.45	$7.35	3.8%
AnnAvg	946	500	446	0		$15.00	$31.90	$35.48	$0.00		$24.67	$0.00	$107.05	$9.31	9.5%
ResAvg	785	500	285	0		$15.00	$31.90	$22.69	$0.00		$20.48	$0.00	$90.07	$7.94	9.7%

SPECIAL RESIDENTIAL ELECTRIC SERVICE RATE R-201A

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05060	$0.06050	$0.07180	$0.07940	$0.035111	$0.00682	
Small	1,017	500	500	17	0	$10.00	$25.30	$30.25	$1.22	$0.00	$35.71	$6.94	$109.42
Medium	1,505	500	500	505	0	$10.00	$25.30	$30.25	$36.26	$0.00	$52.84	$10.26	$164.91
Large	1,999	500	500	999	0	$10.00	$25.30	$30.25	$71.73	$0.00	$70.19	$13.63	$221.10
XLg	2,349	500	500	1,349	0	$10.00	$25.30	$30.25	$96.86	$0.00	$82.48	$16.02	$260.91
AnnAvg	946	500	446	0	0	$10.00	$25.30	$26.97	$0.00	$0.00	$33.21	$6.45	$101.93
ResAvg	1,150	500	500	150	0	$10.00	$25.30	$30.25	$10.77	$0.00	$40.38	$7.84	$124.54

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$15.00	$0.06380	$0.07960	$0.07960		$0.028553	$0.00000			
Small	1,017	500	500	17		$15.00	$31.90	$39.80	$1.35		$29.04	$0.00	$117.09	$7.67	7.0%
Medium	1,505	500	500	505		$15.00	$31.90	$39.80	$40.20		$42.97	$0.00	$169.87	$4.96	3.0%
Large	1,999	500	500	999		$15.00	$31.90	$39.80	$79.52		$57.08	$0.00	$223.30	$2.20	1.0%
XLg	2,349	500	500	1,349		$15.00	$31.90	$39.80	$107.38		$67.07	$0.00	$261.15	$0.24	0.1%
AnnAvg	946	500	446	0		$15.00	$31.90	$35.48	$0.00		$27.00	$0.00	$109.38	$7.45	7.3%
ResAvg	1,150	500	500	150		$15.00	$31.90	$39.80	$11.94		$32.84	$0.00	$131.48	$6.94	5.6%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-201A

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05060	$0.05870	$0.07030	$0.07840	$0.031532	$0.00682			
Small	691	500	191	0	0	$10.00	$25.30	$11.18	$0.00	$0.00	$21.77	$4.71	$72.96	$63.96	-12.3%
Medium	1,009	500	500	9	0	$10.00	$25.30	$29.35	$0.63	$0.00	$31.82	$6.88	$103.98	$94.98	-8.7%
Large	1,342	500	500	342	0	$10.00	$25.30	$29.35	$24.04	$0.00	$42.32	$9.15	$140.16	$131.16	-6.4%
XLg	1,581	500	500	581	0	$10.00	$25.30	$29.35	$40.84	$0.00	$49.85	$10.78	$166.12	$157.12	-5.4%
AnnAvg	862	500	362	0	0	$10.00	$25.30	$21.24	$0.00	$0.00	$27.17	$5.88	$89.59	$80.59	-10.0%
ResAvg	785	500	285	0	0	$10.00	$25.30	$16.73	$0.00	$0.00	$24.75	$5.35	$82.13	$73.13	-11.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06380	$0.07960	$0.07960		$0.026086	$0.00000				
Small	691	500	191	0		$15.00	$31.90	$15.16	$0.00		$18.01	$0.00	$80.07	$65.07	$1.11	1.7%
Medium	1,009	500	500	9		$15.00	$31.90	$39.80	$0.72		$26.32	$0.00	$113.74	$98.74	$3.76	4.0%
Large	1,342	500	500	342		$15.00	$31.90	$39.80	$27.22		$35.01	$0.00	$148.93	$133.93	$2.77	2.1%
XLg	1,581	500	500	581		$15.00	$31.90	$39.80	$46.25		$41.24	$0.00	$174.19	$159.19	$2.07	1.3%
AnnAvg	862	500	362	0		$15.00	$31.90	$28.80	$0.00		$22.48	$0.00	$98.18	$83.18	$2.59	3.2%
ResAvg	785	500	285	0		$15.00	$31.90	$22.69	$0.00		$20.48	$0.00	$90.07	$75.07	$1.94	2.7%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-201A

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	3500	>3500		500	1000	3500	>3500					
						$10.00	$0.05060	$0.06050	$0.07180	$0.07940	$0.035111	$0.00682			
Small	877	500	377	0	0	$10.00	$25.30	$22.81	$0.00	$0.00	$30.79	$5.98	$94.88	$85.88	-9.5%
Medium	1,268	500	500	268	0	$10.00	$25.30	$30.25	$19.24	$0.00	$44.52	$8.65	$137.96	$128.96	-6.5%
Large	1,815	500	500	815	0	$10.00	$25.30	$30.25	$58.52	$0.00	$63.73	$12.38	$200.18	$191.18	-4.5%
XLg	2,060	500	500	1,060	0	$10.00	$25.30	$30.25	$76.11	$0.00	$72.33	$14.05	$228.04	$219.04	-3.9%
AnnAvg	862	500	362	0	0	$10.00	$25.30	$21.89	$0.00	$0.00	$30.26	$5.88	$93.33	$84.33	-9.6%
ResAvg	1,150	500	500	150	0	$10.00	$25.30	$30.25	$10.77	$0.00	$40.38	$7.84	$124.54	$115.54	-7.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000			500	1000	>1000							
						$15.00	$0.06380	$0.07960	$0.07960		$0.028553	$0.00000				
Small	877	500	377	0		$15.00	$31.90	$30.01	$0.00		$25.04	$0.00	$101.95	$86.95	$1.07	1.2%
Medium	1,268	500	500	268		$15.00	$31.90	$39.80	$21.33		$36.21	$0.00	$144.24	$129.24	$0.28	0.2%
Large	1,815	500	500	815		$15.00	$31.90	$39.80	$64.87		$51.82	$0.00	$203.39	$188.39	-$2.79	-1.5%
XLg	2,060	500	500	1,060		$15.00	$31.90	$39.80	$84.38		$58.82	$0.00	$229.90	$214.90	-$4.14	-1.9%
AnnAvg	862	500	362	0		$15.00	$31.90	$28.80	$0.00		$24.61	$0.00	$100.31	$85.31	$0.98	1.2%
ResAvg	1,150	500	500	150		$15.00	$31.90	$39.80	$11.94		$32.84	$0.00	$131.48	$116.48	$0.94	0.8%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

WINTER

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-06-201AF FROZEN

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.04130	$0.04130	$0.04130	$0.027198	$0.00682			
Small	694	500	194	0	$6.90	$20.65	$7.99	$0.00	$18.86	$4.73	$59.13	$50.13	-15.2%
Medium	1,030	500	500	30	$6.90	$20.65	$20.65	$1.24	$28.01	$7.02	$84.47	$75.47	-10.7%
Large	1,310	500	500	310	$6.90	$20.65	$20.65	$12.80	$35.63	$8.93	$105.56	$96.56	-8.5%
XLg	1,524	500	500	524	$6.90	$20.65	$20.65	$21.64	$41.45	$10.39	$121.68	$112.68	-7.4%
AnnAvg	899	500	399	0	$6.90	$20.65	$16.48	$0.00	$24.45	$6.13	$74.61	$65.61	-12.1%
ResAvg	785	500	285	0	$6.90	$20.65	$11.77	$0.00	$21.35	$5.35	$66.02	$57.02	-13.6%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.026086	$0.00000				
Small	694	500	194	0	$15.00	$31.90	$15.40	$0.00	$18.09	$0.00	$80.39	$62.39	$12.26	24.5%
Medium	1,030	500	500	30	$15.00	$31.90	$39.80	$2.39	$26.87	$0.00	$115.96	$97.96	$22.49	29.8%
Large	1,310	500	500	310	$15.00	$31.90	$39.80	$24.68	$34.17	$0.00	$145.55	$127.55	$30.99	32.1%
XLg	1,524	500	500	524	$15.00	$31.90	$39.80	$41.71	$39.76	$0.00	$168.17	$150.17	$37.49	33.3%
AnnAvg	899	500	399	0	$15.00	$31.90	$31.76	$0.00	$23.45	$0.00	$102.11	$84.11	$18.50	28.2%
ResAvg	785	500	285	0	$15.00	$31.90	$22.69	$0.00	$20.48	$0.00	$90.07	$72.07	$15.05	26.4%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-06-201AF FROZEN

Summer

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
	Mid-Summer				$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	940	500	440	0	$6.90	$30.55	$26.88	$0.00	$31.21	$6.41	$101.95	$92.95	-8.8%
Medium	1,471	500	500	471	$6.90	$30.55	$30.55	$28.75	$48.82	$10.03	$155.60	$146.60	-5.8%
Large	1,869	500	500	869	$6.90	$30.55	$30.55	$53.10	$62.05	$12.75	$195.90	$186.90	-4.6%
XLg	2,135	500	500	1,135	$6.90	$30.55	$30.55	$69.35	$70.88	$14.56	$222.79	$213.79	-4.0%
AnnAvg	899	500	399	0	$6.90	$30.55	$24.38	$0.00	$29.85	$6.13	$97.81	$88.81	-9.2%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$114.19	-7.3%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.02855	$0.00000				
Small	940	500	440	0	$15.00	$31.90	$35.02	$0.00	$26.84	$0.00	$108.76	$90.76	-$2.19	-2.4%
Medium	1,471	500	500	471	$15.00	$31.90	$39.80	$37.45	$41.99	$0.00	$166.14	$148.14	$1.54	1.1%
Large	1,869	500	500	869	$15.00	$31.90	$39.80	$69.17	$53.37	$0.00	$209.24	$191.24	$4.34	2.3%
XLg	2,135	500	500	1,135	$15.00	$31.90	$39.80	$90.35	$60.96	$0.00	$238.01	$220.01	$6.22	2.9%
AnnAvg	899	500	399	0	$15.00	$31.90	$31.76	$0.00	$25.67	$0.00	$104.33	$86.33	-$2.48	-2.8%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$32.84	$0.00	$131.48	$113.48	-$0.71	-0.6%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-08-201A FROZEN

WINTER

	BILL IMPACTS CURRENT RATES												Percentage Discount
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	
		500	1000	>1000		500	1000	>1000					
					$6.90	$0.04130	$0.04130	$0.04130	$0.027198	$0.00682			
Small	1,201	500	500	201	$6.90	$20.65	$20.65	$8.28	$32.65	$8.19	$97.32	$68.12	-30.0%
Medium	1,630	500	500	630	$6.90	$20.65	$20.65	$26.02	$44.33	$11.12	$129.67	$90.77	-30.0%
Large	2,051	500	500	1,051	$6.90	$20.65	$20.65	$43.41	$55.78	$13.99	$161.38	$145.24	-10.0%
XLg	2,310	500	500	1,310	$6.90	$20.65	$20.65	$54.10	$62.83	$15.75	$180.88	$162.79	-10.0%
AnnAvg	1,382	500	500	382	$6.90	$20.65	$20.65	$15.78	$37.59	$9.43	$111.00	$77.70	-30.0%
ResAvg	785	500	285	0	$6.90	$20.65	$11.77	$0.00	$21.35	$5.35	$66.02	$42.91	-35.0%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
					$15.00	$0.06380	$0.07960	$0.07960	$0.026086	$0.00000				
Small	1,201	500	500	201	$15.00	$31.90	$39.80	$15.96	$31.32	$0.00	$133.98	$93.98	$25.86	38.0%
Medium	1,630	500	500	630	$15.00	$31.90	$39.80	$50.15	$42.52	$0.00	$179.37	$139.37	$48.60	53.5%
Large	2,051	500	500	1,051	$15.00	$31.90	$39.80	$83.66	$53.50	$0.00	$223.86	$183.86	$38.62	26.6%
XLg	2,310	500	500	1,310	$15.00	$31.90	$39.80	$104.28	$60.26	$0.00	$251.24	$211.24	$48.45	29.8%
AnnAvg	1,382	500	500	382	$15.00	$31.90	$39.80	$30.42	$36.05	$0.00	$153.17	$113.17	$35.47	45.6%
ResAvg	785	500	285	0	$15.00	$31.90	$22.69	$0.00	$20.48	$0.00	$90.07	$50.07	$7.16	16.7%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE RATE R-08-201A FROZEN

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS 500	1000	>1000	Basic Service Charge	Delivery 500	1000	>1000	Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
	Mid-Summer				$6.90	$0.06110	$0.06110	$0.06110	$0.033198	$0.00682			
Small	1,586	500	500	586	$6.90	$30.55	$30.55	$35.80	$52.65	$10.82	$167.27	$117.09	-30.0%
Medium	2,062	500	500	1,062	$6.90	$30.55	$30.55	$64.89	$68.45	$14.06	$215.40	$193.86	-10.0%
Large	2,487	500	500	1,487	$6.90	$30.55	$30.55	$90.86	$82.56	$16.96	$258.38	$232.54	-10.0%
XLg	2,710	500	500	1,710	$6.90	$30.55	$30.55	$104.48	$89.97	$18.48	$280.93	$252.84	-10.0%
AnnAvg	1,382	500	500	382	$6.90	$30.55	$30.55	$23.35	$45.88	$9.43	$146.66	$102.66	-30.0%
ResAvg	1,150	500	500	150	$6.90	$30.55	$30.55	$9.17	$38.18	$7.84	$123.19	$86.23	-30.0%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS 500	1000	>1000	Basic Service Charge	Delivery 500	1000	>1000	Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
					$15.00	$0.06380	$0.07960	$0.07960	$0.028553	$0.00000				
Small	1,586	500	500	586	$15.00	$31.90	$39.80	$46.65	$45.29	$0.00	$178.64	$138.64	$21.55	18.4%
Medium	2,062	500	500	1,062	$15.00	$31.90	$39.80	$84.54	$58.88	$0.00	$230.12	$190.12	-$3.74	-1.9%
Large	2,487	500	500	1,487	$15.00	$31.90	$39.80	$118.37	$71.01	$0.00	$276.08	$236.08	$3.54	1.5%
XLg	2,710	500	500	1,710	$15.00	$31.90	$39.80	$136.12	$77.38	$0.00	$300.20	$260.20	$7.36	2.9%
AnnAvg	1,382	500	500	382	$15.00	$31.90	$39.80	$30.42	$39.46	$0.00	$156.58	$116.58	$13.92	13.6%
ResAvg	1,150	500	500	150	$15.00	$31.90	$39.80	$11.94	$32.84	$0.00	$131.48	$91.48	$5.25	6.1%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Winter

SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201B

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000		500	1000	>1000			
On-Peak	0.27				$11.50	$0.04830	$0.04830	$0.04830	$0.032893	$0.00682	
Off-Peak	0.73					$0.03550	$0.03550	$0.03550	$0.027092		
Small	838	500	338	0	$11.50	$19.47	$13.14	$0.00	$24.00	$5.71	$73.82
Medium	1,258	500	500	258	$11.50	$19.47	$19.47	$10.05	$36.04	$8.58	$105.11
Large	1,800	500	500	800	$11.50	$19.47	$19.47	$31.15	$51.57	$12.28	$145.44
XLg	2,221	500	500	1,221	$11.50	$19.47	$19.47	$47.55	$63.63	$15.15	$176.77
AnnAvg	1,097	500	500	97	$11.50	$19.47	$19.47	$3.76	$31.42	$7.48	$93.10
ResAvg	785	500	285	0	$11.50	$19.47	$11.10	$0.00	$22.49	$5.35	$69.91

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000		500	1000	>1000					
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.026054	$0.00000			
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.020524				
Small	838	500	338	0	$12.00	$31.90	$26.87	$0.00	$18.12	$0.00	$88.89	$15.07	20.4%
Medium	1,258	500	500	258	$12.00	$31.90	$39.80	$20.54	$27.21	$0.00	$131.45	$26.34	25.1%
Large	1,800	500	500	800	$12.00	$31.90	$39.80	$63.68	$38.93	$0.00	$186.31	$40.87	28.1%
XLg	2,221	500	500	1,221	$12.00	$31.90	$39.80	$97.19	$48.04	$0.00	$228.93	$52.16	29.5%
AnnAvg	1,097	500	500	97	$12.00	$31.90	$39.80	$7.69	$23.72	$0.00	$115.11	$22.01	23.6%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$16.98	$0.00	$83.57	$13.66	19.5%

SPECIAL RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201B

Summer

	BILL IMPACTS CURRENT RATES										
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill
		500	1000	>1000	$11.50	500	1000	>1000			
On-Peak	0.23					$0.05680	$0.05680	$0.05680	$0.050669	$0.00682	
Off-Peak	0.77					$0.04400	$0.04400	$0.04400	$0.026679		
Small	1,066	500	500	66	$11.50	$23.45	$23.45	$3.10	$34.25	$7.27	$103.02
Medium	1,609	500	500	609	$11.50	$23.45	$23.45	$28.57	$51.69	$10.97	$149.63
Large	2,283	500	500	1,283	$11.50	$23.45	$23.45	$60.18	$73.34	$15.57	$207.49
XLg	2,790	500	500	1,790	$11.50	$23.45	$23.45	$83.96	$89.63	$19.03	$251.02
AnnAvg	1,097	500	500	97	$11.50	$23.45	$23.45	$4.53	$35.23	$7.48	$105.64
ResAvg	1,150	500	500	150	$11.50	$23.45	$23.45	$7.04	$36.94	$7.84	$110.22

	BILL IMPACTS PROPOSED RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill		
		500	1000	>1000		500	1000	>1000					
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.053254	$0.00000			
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.021066			$ Change	% Change
Small	1,066	500	500	66	$12.00	$31.90	$39.80	$5.25	$27.95	$0.00	$116.90	$13.88	13.5%
Medium	1,609	500	500	609	$12.00	$31.90	$39.80	$48.48	$42.18	$0.00	$174.36	$24.73	16.5%
Large	2,283	500	500	1,283	$12.00	$31.90	$39.80	$102.13	$59.85	$0.00	$245.68	$38.19	18.4%
XLg	2,790	500	500	1,790	$12.00	$31.90	$39.80	$142.48	$73.14	$0.00	$299.32	$48.30	19.2%
AnnAvg	1,097	500	500	97	$12.00	$31.90	$39.80	$7.69	$28.75	$0.00	$120.14	$14.50	13.7%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$30.15	$0.00	$125.79	$15.57	14.1%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201BL

Winter

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.27				$11.50	$0.04830	$0.04830	$0.04830	$0.032893	$0.00682			
Off-Peak	0.73					$0.03550	$0.03550	$0.03550	$0.027092				
Small	915	500	415	0	$11.50	$19.47	$16.16	$0.00	$26.22	$6.24	$79.59	$70.59	-11.3%
Medium	1,231	500	500	231	$11.50	$19.47	$19.47	$9.00	$35.27	$8.40	$103.11	$94.11	-8.7%
Large	1,524	500	500	524	$11.50	$19.47	$19.47	$20.40	$43.66	$10.39	$124.89	$115.89	-7.2%
XLg	2,733	500	500	1,733	$11.50	$19.47	$19.47	$67.48	$78.30	$18.64	$214.86	$205.86	-4.2%
AnnAvg	1,370	500	500	370	$11.50	$19.47	$19.47	$14.41	$39.25	$9.34	$113.44	$104.44	-7.9%
ResAvg	785	500	285	0	$11.50	$19.47	$11.10	$0.00	$22.49	$5.35	$69.91	$60.91	-12.9%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.026054	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.020524					
Small	915	500	415	0	$12.00	$31.90	$33.03	$0.00	$19.79	$0.00	$96.72	$81.72	$11.13	15.8%
Medium	1,231	500	500	231	$12.00	$31.90	$39.80	$18.39	$26.63	$0.00	$128.72	$113.72	$19.61	20.8%
Large	1,524	500	500	524	$12.00	$31.90	$39.80	$41.71	$32.96	$0.00	$158.37	$143.37	$27.48	23.7%
XLg	2,733	500	500	1,733	$12.00	$31.90	$39.80	$137.95	$59.11	$0.00	$280.76	$265.76	$59.90	29.1%
AnnAvg	1,370	500	500	370	$12.00	$31.90	$39.80	$29.45	$29.63	$0.00	$142.78	$127.78	$23.34	22.3%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$16.98	$0.00	$83.57	$68.57	$7.66	12.6%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-201BL

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000	$11.50	500	1000	>1000					
On-Peak	0.23					$0.05680	$0.05680	$0.05680	$0.050669	$0.00682			
Off-Peak	0.77					$0.04400	$0.04400	$0.04400	$0.026679				
Small	1,119	500	500	119	$11.50	$23.45	$23.45	$5.58	$35.95	$7.63	$107.56	$98.56	-8.4%
Medium	3,060	500	500	2,060	$11.50	$23.45	$23.45	$96.63	$98.30	$20.87	$274.20	$265.20	-3.3%
Large	3,869	500	500	2,869	$11.50	$23.45	$23.45	$134.57	$124.29	$26.39	$343.65	$334.65	-2.6%
XLg	3,869	500	500	2,869	$11.50	$23.45	$23.45	$134.57	$124.29	$26.39	$343.65	$334.65	-2.6%
AnnAvg	1,370	500	500	370	$11.50	$23.45	$23.45	$17.35	$44.01	$9.34	$129.10	$120.10	-7.0%
ResAvg	1,150	500	500	150	$11.50	$23.45	$23.45	$7.04	$36.94	$7.84	$110.22	$101.22	-8.2%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.053254	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.021066					
Small	1,119	500	500	119	$12.00	$31.90	$39.80	$9.47	$29.34	$0.00	$122.51	$107.51	$8.95	9.1%
Medium	3,060	500	500	2,060	$12.00	$31.90	$39.80	$163.98	$80.22	$0.00	$327.90	$312.90	$47.70	18.0%
Large	3,869	500	500	2,869	$12.00	$31.90	$39.80	$228.37	$101.43	$0.00	$413.50	$398.50	$63.85	19.1%
XLg	3,869	500	500	2,869	$12.00	$31.90	$39.80	$228.37	$101.43	$0.00	$413.50	$398.50	$63.85	19.1%
AnnAvg	1,370	500	500	370	$12.00	$31.90	$39.80	$29.45	$35.91	$0.00	$149.06	$134.06	$13.96	11.6%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$30.15	$0.00	$125.79	$110.79	$9.57	9.5%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-06-201BF

Winter

	BILL IMPACTS CURRENT RATES												
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.24				$8.78	$0.06520	$0.06520	$0.06520	$0.040698	$0.00682			
Shldr-Peak	N/A												
Off-Peak	0.76					$0.01530	$0.01530	$0.01530	$0.020698				
Small	515	500	15	0	$8.78	$13.52	$0.41	$0.00	$13.08	$3.51	$39.30	$30.30	-22.9%
Medium	1,064	500	500	64	$8.78	$13.52	$13.52	$1.73	$27.03	$7.26	$71.84	$62.84	-12.5%
Large	1,311	500	500	311	$8.78	$13.52	$13.52	$8.40	$33.29	$8.94	$86.45	$77.45	-10.4%
XLg	1,647	500	500	647	$8.78	$13.52	$13.52	$17.50	$41.84	$11.23	$106.39	$97.39	-8.5%
AnnAvg	745	500	245	0	$8.78	$13.52	$6.62	$0.00	$18.92	$5.08	$52.92	$43.92	-17.0%
ResAvg	785	500	285	0	$8.78	$13.52	$7.71	$0.00	$19.94	$5.35	$55.30	$46.30	-16.3%

	BILL IMPACTS PROPOSED RATES													
	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount		
		500	1000	>1000		500	1000	>1000						
On-Peak	0.20				$12.00	$0.06380	$0.07960	$0.07960	$0.027683	$0.00000				
Off-Peak	0.80					$0.06380	$0.07960	$0.07960	$0.021807				$ Change	% Change
Small	515	500	15	0	$12.00	$31.90	$1.19	$0.00	$11.84	$0.00	$56.93	$41.93	$11.63	38.4%
Medium	1,064	500	500	64	$12.00	$31.90	$39.80	$5.09	$24.45	$0.00	$113.24	$98.24	$35.40	56.3%
Large	1,311	500	500	311	$12.00	$31.90	$39.80	$24.72	$30.12	$0.00	$138.54	$123.54	$46.09	59.5%
XLg	1,647	500	500	647	$12.00	$31.90	$39.80	$51.50	$37.85	$0.00	$173.05	$158.05	$60.66	62.3%
AnnAvg	745	500	245	0	$12.00	$31.90	$19.50	$0.00	$17.12	$0.00	$80.52	$65.52	$21.60	49.2%
ResAvg	785	500	285	0	$12.00	$31.90	$22.69	$0.00	$18.04	$0.00	$84.63	$69.63	$23.33	50.4%

SPECIAL LIFELINE RESIDENTIAL ELECTRIC SERVICE TIME OF USE RATE R-06-201BF

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	Percentage Discount
		500	1000	>1000		500	1000	>1000					
On-Peak	0.18				$8.78	$0.13690	$0.13690	$0.13690	$0.055698	$0.00682			
Shldr-Peak	0.09					$0.07470	$0.07470	$0.07470	$0.048198				
Off-Peak	0.72					$0.03830	$0.03830	$0.03830	$0.023198				
Small	559	500	59	0	$8.78	$29.89	$3.50	$0.00	$17.57	$3.81	$63.55	$54.55	-14.2%
Medium	1,492	500	500	492	$8.78	$29.89	$29.89	$29.41	$46.95	$10.18	$155.10	$146.10	-5.8%
Large	1,824	500	500	824	$8.78	$29.89	$29.89	$49.26	$57.39	$12.44	$187.65	$178.65	-4.8%
XLg	1,862	500	500	862	$8.78	$29.89	$29.89	$51.54	$58.59	$12.70	$191.39	$182.39	-4.7%
AnnAvg	745	500	245	0	$8.78	$29.89	$14.64	$0.00	$23.44	$5.08	$81.83	$72.83	-11.0%
ResAvg	1,150	500	500	150	$8.78	$29.89	$29.89	$8.97	$36.19	$7.84	$121.56	$112.56	-7.4%

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS			Basic Service Charge	Delivery			Base Fuel	PPFAC	Net Bill	Net Bill with Discount	$ Change	% Change
		500	1000	>1000		500	1000	>1000						
On-Peak	0.16				$12.00	$0.06380	$0.07960	$0.07960	$0.056583	$0.00000				
Off-Peak	0.84					$0.06380	$0.07960	$0.07960	$0.022382					
Small	559	500	59	0	$12.00	$31.90	$4.66	$0.00	$15.56	$0.00	$64.12	$49.12	-$5.43	-10.0%
Medium	1,492	500	500	492	$12.00	$31.90	$39.80	$39.16	$41.56	$0.00	$164.42	$149.42	$3.32	2.3%
Large	1,824	500	500	824	$12.00	$31.90	$39.80	$65.59	$50.81	$0.00	$200.10	$185.10	$6.45	3.6%
XLg	1,862	500	500	862	$12.00	$31.90	$39.80	$68.62	$51.86	$0.00	$204.18	$189.18	$6.79	3.7%
AnnAvg	745	500	245	0	$12.00	$31.90	$19.50	$0.00	$20.75	$0.00	$84.15	$69.15	-$3.68	-5.1%
ResAvg	1,150	500	500	150	$12.00	$31.90	$39.80	$11.94	$32.03	$0.00	$127.67	$112.67	$0.11	0.1%

PREPAY ELECTRIC SERVICE

WINTER

BILL IMPACTS CURRENT R-01 RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh/day) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		16	>16			($/day)	16	>16							
						$0.67	$0.06380	$0.07960			$0.032608	$0.00000			
Small	520	480	40			$20.10	$30.63	$3.18			$16.96	$0.00	$70.87	$11.52	19.4%
Medium	840	480	360			$20.10	$30.63	$28.66			$27.39	$0.00	$106.78	$14.29	15.5%
Large	1,250	480	770			$20.10	$30.63	$61.29			$40.76	$0.00	$152.78	$14.60	10.6%
XLg	1,564	480	1,084			$20.10	$30.63	$86.29			$51.00	$0.00	$188.02	$13.28	7.6%
AnnAvg	785	480	305			$20.10	$30.63	$24.28			$25.60	$0.00	$100.61	$13.83	15.9%
ResAvg	785	480	305			$20.10	$30.63	$24.28			$25.60	$0.00	$100.61	$13.83	15.9%

Note: Prepay Electric Service bill calculations assume 30 days per month.

PREPAY ELECTRIC SERVICE

SUMMER

BILL IMPACTS CURRENT R-01 RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh/day) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		16	>16			($/day)	16	>16							
						$0.67	$0.06380	$0.07960			$0.035691	$0.00000			
Small	822	480	342			$20.10	$30.63	$27.22			$29.34	$0.00	$107.29	$13.08	13.9%
Medium	1,384	480	904			$20.10	$30.63	$71.96			$49.40	$0.00	$172.09	$11.72	7.3%
Large	1,997	480	1,517			$20.10	$30.63	$120.75			$71.27	$0.00	$242.75	$7.75	3.3%
XLg	2,430	480	1,950			$20.10	$30.63	$155.22			$86.73	$0.00	$292.68	$4.98	1.7%
AnnAvg	785	480	305			$20.10	$30.63	$24.28			$28.02	$0.00	$103.03	$12.87	14.3%
ResAvg	1,150	480	670			$20.10	$30.63	$53.33			$41.04	$0.00	$145.10	$13.21	10.0%

Note: Prepay Electric Service bill calculations assume 30 days per month.

Small General Service RATE GS-10

WINTER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$33.62
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$85.12
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$209.16
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$436.36
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$609.68
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$188.50
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$161.75

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.06630	$0.08730	$0.032608	$0.00000			
										$ Change	% Change
Xsm	190	190	0	$27.00	$12.60	$0.00	$6.20	$0.00	$45.80	$12.18	36.2%
Small	687	500	187	$27.00	$33.15	$16.33	$22.40	$0.00	$98.88	$13.76	16.2%
Medium	1,744	500	1,244	$27.00	$33.15	$108.60	$56.87	$0.00	$225.62	$16.46	7.9%
Large	3,680	500	3,180	$27.00	$33.15	$277.61	$120.00	$0.00	$457.76	$21.40	4.9%
XLg	5,157	500	4,657	$27.00	$33.15	$406.56	$168.16	$0.00	$634.87	$25.19	4.1%
AnnAvg	1,568	500	1,068	$27.00	$33.15	$93.24	$51.13	$0.00	$204.52	$16.02	8.5%
SGSAvg	1,340	500	840	$27.00	$33.15	$73.33	$43.69	$0.00	$177.17	$15.42	9.5%

Small General Service RATE GS-10

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$41.18
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$128.35
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$334.02
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$678.61
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$939.90
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$224.19
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$268.58

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	>500		500	>500					
				$27.00	$0.08625	$0.10110	$0.035691	$0.00000			
Xsm	216	216	0	$27.00	$18.63	$0.00	$7.71	$0.00	$53.34	$12.16	29.5%
Small	882	500	382	$27.00	$43.13	$38.62	$31.48	$0.00	$140.23	$11.88	9.3%
Medium	2,354	500	1,854	$27.00	$43.13	$187.44	$84.02	$0.00	$341.59	$7.57	2.3%
Large	4,820	500	4,320	$27.00	$43.13	$436.75	$172.03	$0.00	$678.91	$0.30	0.0%
XLg	6,690	500	6,190	$27.00	$43.13	$625.81	$238.77	$0.00	$934.71	-$5.19	-0.6%
AnnAvg	1,568	500	1,068	$27.00	$43.13	$107.98	$55.96	$0.00	$234.07	$9.88	4.4%
SGSAvg	1,886	500	1,386	$27.00	$43.13	$140.09	$67.30	$0.00	$277.52	$8.94	3.3%

SMALL GENERAL SERVICE DEMAND

WINTER

BILL IMPACTS CURRENT GS-10 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500					500	>500					
								$15.50	$0.05700	$0.07900			$0.031532	$0.00682	
Xsm	0.25	190	190	0	1.1			$15.50	$10.83	$0.00			$5.99	$1.30	$33.62
Small	0.33	687	500	187	2.8			$15.50	$28.50	$14.77			$21.66	$4.69	$85.12
Medium	0.41	1,744	500	1,244	5.9			$15.50	$28.50	$98.28			$54.99	$11.89	$209.16
Large	0.48	3,680	500	3,180	10.4			$15.50	$28.50	$251.22			$116.04	$25.10	$436.36
XLg	0.52	5,157	500	4,657	13.6			$15.50	$28.50	$367.90			$162.61	$35.17	$609.68
AnnAvg	0.40	1,568	500	1,068	5.4			$15.50	$28.50	$84.37			$49.44	$10.69	$188.50
SGSAvg	0.39	1,340	500	840	4.8			$15.50	$28.50	$66.36			$42.25	$9.14	$161.75

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
								$22.00	$0.05389	$0.05389	$9.95	$13.50	$0.032608	$0.00000			
																$ Change	% Change
Xsm	0.25	190	190	0	1.1	1.1	0.0	$22.00	$10.24	$0.00	$10.45	$0.00	$6.20	$0.00	$48.89	$15.27	45.4%
Small	0.33	687	500	187	2.8	2.8	0.0	$22.00	$26.95	$10.08	$28.26	$0.00	$22.40	$0.00	$109.69	$24.57	28.9%
Medium	0.41	1,744	500	1,244	5.9	5.9	0.0	$22.00	$26.95	$67.04	$58.21	$0.00	$56.87	$0.00	$231.07	$21.91	10.5%
Large	0.48	3,680	500	3,180	10.4	7.0	3.4	$22.00	$26.95	$171.37	$69.65	$46.44	$120.00	$0.00	$456.41	$20.05	4.6%
XLg	0.52	5,157	500	4,657	13.6	7.0	6.6	$22.00	$26.95	$250.97	$69.65	$88.56	$168.16	$0.00	$626.29	$16.61	2.7%
AnnAvg	0.40	1,568	500	1,068	5.4	5.4	0.0	$22.00	$26.95	$57.56	$53.53	$0.00	$51.13	$0.00	$211.17	$22.67	12.0%
SGSAvg	0.39	1,340	500	840	4.8	4.8	0.0	$22.00	$26.95	$45.27	$47.46	$0.00	$43.69	$0.00	$185.37	$23.62	14.6%

SMALL GENERAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT GS-10 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500					500	>500					
								$15.50	$0.07700	$0.09780			$0.035111	$0.00682	
Xsm	0.26	216	216	0	1.2			$15.50	$16.63	$0.00			$7.58	$1.47	$41.18
Small	0.35	882	500	382	3.5			$15.50	$38.50	$37.36			$30.97	$6.02	$128.35
Medium	0.44	2,354	500	1,854	7.4			$15.50	$38.50	$181.32			$82.65	$16.05	$334.02
Large	0.51	4,820	500	4,320	12.9			$15.50	$38.50	$422.50			$169.24	$32.87	$678.61
XLg	0.55	6,690	500	6,190	16.6			$15.50	$38.50	$605.38			$234.89	$45.63	$939.90
AnnAvg	0.40	1,568	500	1,068	5.4			$15.50	$38.50	$104.45			$55.05	$10.69	$224.19
SGSAvg	0.42	1,886	500	1,386	6.2			$15.50	$38.50	$135.51			$66.21	$12.86	$268.58

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill		
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
								$22.00	$0.06389	$0.06389	$9.95	$13.50	$0.035691	$0.00000			
																$ Change	% Change
Xsm	0.26	216	216	0	1.2	1.2	0.0	$22.00	$13.80	$0.00	$11.54	$0.00	$7.71	$0.00	$55.05	$13.87	33.7%
Small	0.35	882	500	382	3.5	3.5	0.0	$22.00	$31.95	$24.41	$34.33	$0.00	$31.48	$0.00	$144.17	$15.82	12.3%
Medium	0.44	2,354	500	1,854	7.4	7.0	0.4	$22.00	$31.95	$118.45	$69.65	$5.13	$84.02	$0.00	$331.20	-$2.82	-0.8%
Large	0.51	4,820	500	4,320	12.9	7.0	5.9	$22.00	$31.95	$276.00	$69.65	$79.25	$172.03	$0.00	$650.88	-$27.73	-4.1%
XLg	0.55	6,690	500	6,190	16.6	7.0	9.6	$22.00	$31.95	$395.48	$69.65	$129.47	$238.77	$0.00	$887.32	-$52.58	-5.6%
AnnAvg	0.40	1,568	500	1,068	5.4	5.4	0.0	$22.00	$31.95	$68.24	$53.53	$0.00	$55.96	$0.00	$231.68	$7.49	3.3%
SGSAvg	0.42	1,886	500	1,386	6.2	6.2	0.0	$22.00	$31.95	$88.53	$61.79	$0.00	$67.30	$0.00	$271.57	$2.99	1.1%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Small General Service (Municipal Transitional Adjustment) RATE GSM-10

WINTER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	190	190	0	$15.50	$10.83	$0.00	$5.99	$1.30	$30.63
Small	687	500	187	$15.50	$28.50	$14.77	$21.66	$4.69	$73.63
Medium	1,744	500	1,244	$15.50	$28.50	$98.28	$54.99	$11.89	$177.21
Large	3,680	500	3,180	$15.50	$28.50	$251.22	$116.04	$25.10	$366.92
XLg	5,157	500	4,657	$15.50	$28.50	$367.90	$162.61	$35.17	$511.64
AnnAvg	1,568	500	1,068	$15.50	$28.50	$84.37	$49.44	$10.69	$159.96
SGSAvg	1,340	500	840	$15.50	$28.50	$66.36	$42.25	$9.14	$137.62

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.06630	$0.08730	$0.032608	$0.00000			
										$ Change	% Change
Xsm	190	190	0	$27.00	$12.60	$0.00	$6.20	$0.00	$45.80	$15.17	49.5%
Small	687	500	187	$27.00	$33.15	$16.33	$22.40	$0.00	$98.88	$25.25	34.3%
Medium	1,744	500	1,244	$27.00	$33.15	$108.60	$56.87	$0.00	$225.62	$48.41	27.3%
Large	3,680	500	3,180	$27.00	$33.15	$277.61	$120.00	$0.00	$457.76	$90.84	24.8%
XLg	5,157	500	4,657	$27.00	$33.15	$406.56	$168.16	$0.00	$634.87	$123.23	24.1%
AnnAvg	1,568	500	1,068	$27.00	$33.15	$93.24	$51.13	$0.00	$204.52	$44.57	27.9%
SGSAvg	1,340	500	840	$27.00	$33.15	$73.33	$43.69	$0.00	$177.17	$39.55	28.7%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Small General Service (Municipal Transitional Adjustment) RATE GSM-10

SUMMER

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	216	216	0	$15.50	$16.63	$0.00	$7.58	$1.47	$36.94
Small	882	500	382	$15.50	$38.50	$37.36	$30.97	$6.02	$109.73
Medium	2,354	500	1,854	$15.50	$38.50	$181.32	$82.65	$16.05	$281.46
Large	4,820	500	4,320	$15.50	$38.50	$422.50	$169.24	$32.87	$569.20
XLg	6,690	500	6,190	$15.50	$38.50	$605.38	$234.89	$45.63	$787.37
AnnAvg	1,568	500	1,068	$15.50	$38.50	$104.45	$55.05	$10.69	$189.76
SGSAvg	1,886	500	1,386	$15.50	$38.50	$135.51	$66.21	$12.86	$226.82

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
				$27.00	$0.08625	$0.10110	$0.035691	$0.00000			
										$ Change	% Change
Xsm	216	216	0	$27.00	$18.63	$0.00	$7.71	$0.00	$53.34	$16.40	44.4%
Small	882	500	382	$27.00	$43.13	$38.62	$31.48	$0.00	$140.23	$30.50	27.8%
Medium	2,354	500	1,854	$27.00	$43.13	$187.44	$84.02	$0.00	$341.59	$60.13	21.4%
Large	4,820	500	4,320	$27.00	$43.13	$436.75	$172.03	$0.00	$678.91	$109.71	19.3%
XLg	6,690	500	6,190	$27.00	$43.13	$625.81	$238.77	$0.00	$934.71	$147.34	18.7%
AnnAvg	1,568	500	1,068	$27.00	$43.13	$107.98	$55.96	$0.00	$234.07	$44.31	23.4%
SGSAvg	1,886	500	1,386	$27.00	$43.13	$140.09	$67.30	$0.00	$277.52	$50.70	22.4%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Mobile Home Parks Service Rate GS-11 Frozen

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.06200	$0.031532	$0.00682	
Xsm	3,067	$15.50	$190.15	$96.71	$20.92	$323.28
Small	6,520	$15.50	$404.24	$205.59	$44.47	$669.80
Medium	11,218	$15.50	$695.52	$353.73	$76.51	$1,141.26
Large	18,640	$15.50	$1,155.68	$587.76	$127.12	$1,886.06
XLg	27,080	$15.50	$1,678.96	$853.89	$184.69	$2,733.04
AnnAvg	13,623	$15.50	$844.60	$429.55	$92.91	$1,382.56
SGSAvg	12,611	$15.50	$781.85	$397.64	$86.00	$1,280.99

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.08694	$0.032608	$0.00000			
Xsm	3,067	$27.00	$266.64	$100.01	$0.00	$393.65	$70.37	21.8%
Small	6,520	$27.00	$566.85	$212.60	$0.00	$806.45	$136.65	20.4%
Medium	11,218	$27.00	$975.29	$365.80	$0.00	$1,368.09	$226.83	19.9%
Large	18,640	$27.00	$1,620.56	$607.81	$0.00	$2,255.37	$369.31	19.6%
XLg	27,080	$27.00	$2,354.34	$883.02	$0.00	$3,264.36	$531.32	19.4%
AnnAvg	13,623	$27.00	$1,184.34	$444.20	$0.00	$1,655.54	$272.98	19.7%
SGSAvg	12,611	$27.00	$1,096.36	$411.20	$0.00	$1,534.56	$253.57	19.8%

Mobile Home Parks Service Rate GS-11 Frozen

SUMMER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.08200	$0.035111	$0.00682	
Xsm	3,900	$15.50	$319.80	$136.93	$26.60	$498.83
Small	8,480	$15.50	$695.36	$297.74	$57.83	$1,066.43
Medium	17,200	$15.50	$1,410.40	$603.91	$117.30	$2,147.11
Large	26,720	$15.50	$2,191.04	$938.17	$182.23	$3,326.94
XLg	35,920	$15.50	$2,945.44	$1,261.19	$244.97	$4,467.10
AnnAvg	13,623	$15.50	$1,117.05	$478.30	$92.91	$1,703.76
SGSAvg	15,040	$15.50	$1,233.31	$528.08	$102.58	$1,879.47

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.08694	$0.035691	$0.00000			
Xsm	3,900	$27.00	$339.07	$139.19	$0.00	$505.26	$6.43	1.3%
Small	8,480	$27.00	$737.25	$302.66	$0.00	$1,066.91	$0.48	0.0%
Medium	17,200	$27.00	$1,495.37	$613.89	$0.00	$2,136.26	-$10.85	-0.5%
Large	26,720	$27.00	$2,323.04	$953.66	$0.00	$3,303.70	-$23.24	-0.7%
XLg	35,920	$27.00	$3,122.88	$1,282.02	$0.00	$4,431.90	-$35.20	-0.8%
AnnAvg	13,623	$27.00	$1,184.34	$486.20	$0.00	$1,697.54	-$6.22	-0.4%
SGSAvg	15,040	$27.00	$1,307.61	$536.81	$0.00	$1,871.42	-$8.05	-0.4%

Municipal Water Pumping Rate GS-43

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.04800	$0.031532	$0.00682	
Xsm	90	$15.50	$4.32	$2.84	$0.61	$23.27
Small	1,440	$15.50	$69.12	$45.41	$9.82	$139.85
Medium	10,840	$15.50	$520.32	$341.81	$73.93	$951.56
Large	34,240	$15.50	$1,643.52	$1,079.66	$233.52	$2,972.20
XLg	56,800	$15.50	$2,726.40	$1,791.02	$387.38	$4,920.30
AnnAvg	14,343	$15.50	$688.47	$452.27	$97.82	$1,254.06
SGSAvg	12,251	$15.50	$588.04	$386.30	$83.55	$1,073.39

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.06030	$0.032608	$0.00000			
							$ Change	% Change
Xsm	90	$27.00	$5.43	$2.93	$0.00	$35.36	$12.09	52.0%
Small	1,440	$27.00	$86.83	$46.96	$0.00	$160.79	$20.94	15.0%
Medium	10,840	$27.00	$653.64	$353.47	$0.00	$1,034.11	$82.55	8.7%
Large	34,240	$27.00	$2,064.64	$1,116.50	$0.00	$3,208.14	$235.94	7.9%
XLg	56,800	$27.00	$3,424.98	$1,852.13	$0.00	$5,304.11	$383.81	7.8%
AnnAvg	14,343	$27.00	$864.88	$467.70	$0.00	$1,359.58	$105.52	8.4%
SGSAvg	12,251	$27.00	$738.72	$399.48	$0.00	$1,165.20	$91.81	8.6%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Municipal Water Pumping Rate GS-43

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.06800	$0.035111	$0.00682	
Xsm	160	$15.50	$10.85	$5.60	$1.09	$33.04
Small	2,766	$15.50	$188.05	$97.10	$18.86	$319.51
Medium	17,280	$15.50	$1,175.04	$606.72	$117.85	$1,915.11
Large	46,160	$15.50	$3,138.88	$1,620.72	$314.81	$5,089.91
XLg	83,200	$15.50	$5,657.60	$2,921.24	$567.42	$9,161.76
AnnAvg	14,343	$15.50	$975.34	$503.60	$97.82	$1,592.26
SGSAvg	17,209	$15.50	$1,170.21	$604.23	$117.37	$1,907.31

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.07610	$0.035691	$0.00000			
Xsm	160	$27.00	$12.14	$5.69	$0.00	$44.83	$11.79	35.7%
Small	2,766	$27.00	$210.45	$98.70	$0.00	$336.15	$16.64	5.2%
Medium	17,280	$27.00	$1,314.99	$616.74	$0.00	$1,958.73	$43.62	2.3%
Large	46,160	$27.00	$3,512.73	$1,647.50	$0.00	$5,187.23	$97.32	1.9%
XLg	83,200	$27.00	$6,331.44	$2,969.49	$0.00	$9,327.93	$166.17	1.8%
AnnAvg	14,343	$27.00	$1,091.50	$511.92	$0.00	$1,630.42	$38.16	2.4%
SGSAvg	17,209	$27.00	$1,309.59	$614.21	$0.00	$1,950.80	$43.49	2.3%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

WINTER

Municipal Interruptible Water Pumping Rate GS-43

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.02700	$0.028420	$0.00682	
Xsm	90	$15.50	$2.43	$2.56	$0.61	$21.10
Small	1,440	$15.50	$38.88	$40.92	$9.82	$105.12
Medium	10,840	$15.50	$292.68	$308.07	$73.93	$690.18
Large	34,240	$15.50	$924.48	$973.10	$233.52	$2,146.60
XLg	56,800	$15.50	$1,533.60	$1,614.26	$387.38	$3,550.74
AnnAvg	14,343	$15.50	$387.27	$407.63	$97.82	$908.22
SGSAvg	12,251	$15.50	$330.78	$348.17	$83.55	$778.00

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		$27.00	$0.03930	$0.029500	$0.00000			
Xsm	90	$27.00	$3.54	$2.66	$0.00	$33.20	$12.10	57.3%
Small	1,440	$27.00	$56.59	$42.48	$0.00	$126.07	$20.95	19.9%
Medium	10,840	$27.00	$426.01	$319.78	$0.00	$772.79	$82.61	12.0%
Large	34,240	$27.00	$1,345.63	$1,010.08	$0.00	$2,382.71	$236.11	11.0%
XLg	56,800	$27.00	$2,232.24	$1,675.60	$0.00	$3,934.84	$384.10	10.8%
AnnAvg	14,343	$27.00	$563.69	$423.12	$0.00	$1,013.81	$105.59	11.6%
SGSAvg	12,251	$27.00	$481.46	$361.40	$0.00	$869.86	$91.86	11.8%

Municipal Interruptible Water Pumping Rate GS-43

SUMMER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		$15.50	$0.04200	$0.031310	$0.00682	
Xsm	160	$15.50	$6.70	$4.99	$1.09	$28.28
Small	2,766	$15.50	$116.15	$86.59	$18.86	$237.10
Medium	17,280	$15.50	$725.76	$541.04	$117.85	$1,400.15
Large	46,160	$15.50	$1,938.72	$1,445.27	$314.81	$3,714.30
XLg	83,200	$15.50	$3,494.40	$2,604.99	$567.42	$6,682.31
AnnAvg	14,343	$15.50	$602.41	$449.08	$97.82	$1,164.81
SGSAvg	17,209	$15.50	$722.78	$538.81	$117.37	$1,394.46

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
		$27.00	$0.05010	$0.031900	$0.00000			
							$ Change	% Change
Xsm	160	$27.00	$7.99	$5.09	$0.00	$40.08	$11.80	41.7%
Small	2,766	$27.00	$138.55	$88.22	$0.00	$253.77	$16.67	7.0%
Medium	17,280	$27.00	$865.73	$551.23	$0.00	$1,443.96	$43.81	3.1%
Large	46,160	$27.00	$2,312.62	$1,472.50	$0.00	$3,812.12	$97.82	2.6%
XLg	83,200	$27.00	$4,168.32	$2,654.08	$0.00	$6,849.40	$167.09	2.5%
AnnAvg	14,343	$27.00	$718.59	$457.55	$0.00	$1,203.14	$38.33	3.3%
SGSAvg	17,209	$27.00	$862.17	$548.97	$0.00	$1,438.14	$43.68	3.1%

SMALL GENERAL SERVICE TIME OF USE RATE GS-76

Winter

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
On-Peak	0.24			$17.50	$0.08140	$0.08140	$0.032893	$0.00682	
Off-Peak	0.76				$0.06490	$0.06490	$0.027092		
Xsm	190	190	0	$17.50	$13.07	$0.00	$5.41	$1.30	$37.28
Small	687	500	187	$17.50	$34.40	$12.87	$19.55	$4.69	$89.01
Medium	1,744	500	1,244	$17.50	$34.40	$85.59	$49.64	$11.89	$199.02
Large	3,680	500	3,180	$17.50	$34.40	$218.78	$104.74	$25.10	$400.52
XLg	5,157	500	4,657	$17.50	$34.40	$320.40	$146.78	$35.17	$554.25
AnnAvg	1,568	500	1,068	$17.50	$34.40	$73.48	$44.63	$10.69	$180.70
SGSAvg	1,340	500	840	$17.50	$34.40	$57.79	$38.14	$9.14	$156.97

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
On-Peak	0.24			$22.00	$0.06630	$0.08730	$0.038010	$0.00000			
Off-Peak	0.76				$0.06630	$0.08730	$0.025655			$ Change	% Change
Xsm	190	190	0	$22.00	$12.60	$0.00	$5.43	$0.00	$40.03	$2.75	7.4%
Small	687	500	187	$22.00	$33.15	$16.33	$19.63	$0.00	$91.11	$2.10	2.4%
Medium	1,744	500	1,244	$22.00	$33.15	$108.60	$49.83	$0.00	$213.58	$14.56	7.3%
Large	3,680	500	3,180	$22.00	$33.15	$277.61	$105.15	$0.00	$437.91	$37.39	9.3%
XLg	5,157	500	4,657	$22.00	$33.15	$406.56	$147.36	$0.00	$609.07	$54.82	9.9%
AnnAvg	1,568	500	1,068	$22.00	$33.15	$93.24	$44.81	$0.00	$193.20	$12.50	6.9%
SGSAvg	1,340	500	840	$22.00	$33.15	$73.33	$38.29	$0.00	$166.77	$9.80	6.2%

SMALL GENERAL SERVICE TIME OF USE RATE GS-76

Summer

	BILL IMPACTS CURRENT RATES								
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500	$17.50	500	>500			
On-Peak	0.20				$0.09910	$0.09910	$0.050669	$0.00682	
Off-Peak	0.80				$0.08490	$0.08490	$0.026679		
Xsm	216	216	0	$17.50	$18.96	$0.00	$6.81	$1.47	$44.74
Small	882	500	382	$17.50	$43.89	$33.53	$27.82	$6.02	$128.76
Medium	2,354	500	1,854	$17.50	$43.89	$162.75	$74.26	$16.05	$314.45
Large	4,820	500	4,320	$17.50	$43.89	$379.22	$152.06	$32.87	$625.54
XLg	6,690	500	6,190	$17.50	$43.89	$543.37	$211.05	$45.63	$861.44
AnnAvg	1,568	500	1,068	$17.50	$43.89	$93.75	$49.47	$10.69	$215.30
SGSAvg	1,886	500	1,386	$17.50	$43.89	$121.63	$59.48	$12.86	$255.36

	BILL IMPACTS PROPOSED RATES										
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill		
		500	>500		500	>500					
On-Peak	0.20			$22.00	$0.08625	$0.10110	$0.071322	$0.00000			
Off-Peak	0.80				$0.08625	$0.10110	$0.025609			$ Change	% Change
Xsm	216	216	0	$22.00	$18.63	$0.00	$7.54	$0.00	$48.17	$3.43	7.7%
Small	882	500	382	$22.00	$43.13	$38.62	$30.77	$0.00	$134.52	$5.76	4.5%
Medium	2,354	500	1,854	$22.00	$43.13	$187.44	$82.12	$0.00	$334.69	$20.24	6.4%
Large	4,820	500	4,320	$22.00	$43.13	$436.75	$168.14	$0.00	$670.02	$44.48	7.1%
XLg	6,690	500	6,190	$22.00	$43.13	$625.81	$233.38	$0.00	$924.32	$62.88	7.3%
AnnAvg	1,568	500	1,068	$22.00	$43.13	$107.98	$54.70	$0.00	$227.81	$12.51	5.8%
SGSAvg	1,886	500	1,386	$22.00	$43.13	$140.09	$65.78	$0.00	$271.00	$15.64	6.1%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

SMALL GENERAL SERVICE DEMAND TIME OF USE

WINTER

BILL IMPACTS CURRENT GS-76 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500				$17.50	500	>500					
On-Peak		0.24							$0.08140	$0.08140			$0.032893	$0.00682	
Off-Peak		0.76							$0.06490	$0.06490			$0.027092		
Xsm	0.25	190	190	0	1.1			$17.50	$13.07	$0.00			$5.41	$1.30	$37.28
Small	0.33	687	500	187	2.8			$17.50	$34.40	$12.87			$19.55	$4.69	$89.01
Medium	0.41	1,744	500	1,244	5.9			$17.50	$34.40	$85.59			$49.64	$11.89	$199.02
Large	0.48	3,680	500	3,180	10.4			$17.50	$34.40	$218.78			$104.74	$25.10	$400.52
XLg	0.52	5,157	500	4,657	13.6			$17.50	$34.40	$320.40			$146.78	$35.17	$554.25
AnnAvg	0.40	1,568	500	1,068	5.4			$17.50	$34.40	$73.48			$44.63	$10.69	$180.70
SGSAvg	0.39	1,340	500	840	4.8			$17.50	$34.40	$57.79			$38.14	$9.14	$156.97

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill	$ Change	% Change
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
On-Peak		0.24						$22.00	$0.05389	$0.05389	$9.95	$13.50	$0.038010	$0.00000			
Off-Peak		0.76							$0.05389	$0.05389			$0.025655				
Xsm	0.25	190	190	0	1.1	1.1	0.0	$22.00	$10.24	$0.00	$10.45	$0.00	$5.43	$0.00	$48.12	$10.84	29.1%
Small	0.33	687	500	187	2.8	2.8	0.0	$22.00	$26.95	$10.08	$28.26	$0.00	$19.63	$0.00	$106.92	$17.91	20.1%
Medium	0.41	1,744	500	1,244	5.9	5.9	0.0	$22.00	$26.95	$67.04	$58.21	$0.00	$49.83	$0.00	$224.03	$25.01	12.6%
Large	0.48	3,680	500	3,180	10.4	7.0	3.4	$22.00	$26.95	$171.37	$69.65	$46.44	$105.15	$0.00	$441.56	$41.04	10.2%
XLg	0.52	5,157	500	4,657	13.6	7.0	6.6	$22.00	$26.95	$250.97	$69.65	$88.56	$147.36	$0.00	$605.49	$51.24	9.2%
AnnAvg	0.40	1,568	500	1,068	5.4	5.4	0.0	$22.00	$26.95	$57.56	$53.53	$0.00	$44.81	$0.00	$204.85	$24.15	13.4%
SGSAvg	0.39	1,340	500	840	4.8	4.8	0.0	$22.00	$26.95	$45.27	$47.46	$0.00	$38.29	$0.00	$179.97	$23.00	14.7%

SMALL GENERAL SERVICE DEMAND TIME OF USE

SUMMER

BILL IMPACTS CURRENT GS-76 RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill
			500	>500				$17.50	500	>500					
On-Peak		0.20							$0.09910	$0.09910			$0.050669	$0.00682	
Off-Peak		0.80							$0.08490	$0.08490			$0.026679		
Xsm	0.26	216	216	0	1.2			$17.50	$18.96	$0.00			$6.81	$1.47	$44.74
Small	0.35	882	500	382	3.5			$17.50	$43.89	$33.53			$27.82	$6.02	$128.76
Medium	0.44	2,354	500	1,854	7.4			$17.50	$43.89	$162.75			$74.26	$16.05	$314.45
Large	0.51	4,820	500	4,320	12.9			$17.50	$43.89	$379.22			$152.06	$32.87	$625.54
XLg	0.55	6,690	500	6,190	16.6			$17.50	$43.89	$543.37			$211.05	$45.63	$861.44
AnnAvg	0.40	1,568	500	1,068	5.4			$17.50	$43.89	$93.75			$49.47	$10.69	$215.30
SGSAvg	0.42	1,886	500	1,386	6.2			$17.50	$43.89	$121.63			$59.48	$12.86	$255.36

BILL IMPACTS PROPOSED RATES

	Load Factor	kWh	Delivery (kWh) TIERS		kW	Delivery (kW)		Basic Service Charge	Delivery (Energy)		Delivery (Demand)		Base Fuel	PPFAC	Net Bill	$ Change	% Change
			500	>500		7.0	> 7.0		500	>500	7.0	> 7.0					
On-Peak		0.20						$22.00	$0.06389	$0.06389	$9.95	$13.50	$0.07132	$0.00000			
Off-Peak		0.80							$0.06389	$0.06389			$0.025609				
Xsm	0.26	216	216	0	1.2	1.2	0.0	$22.00	$13.80	$0.00	$11.54	$0.00	$7.54	$0.00	$54.88	$10.14	22.7%
Small	0.35	882	500	382	3.5	3.5	0.0	$22.00	$31.95	$24.41	$34.33	$0.00	$30.77	$0.00	$143.46	$14.70	11.4%
Medium	0.44	2,354	500	1,854	7.4	7.0	0.4	$22.00	$31.95	$118.45	$69.65	$5.13	$82.12	$0.00	$329.30	$14.85	4.7%
Large	0.51	4,820	500	4,320	12.9	7.0	5.9	$22.00	$31.95	$276.00	$69.65	$79.25	$168.14	$0.00	$646.99	$21.45	3.4%
XLg	0.55	6,690	500	6,190	16.6	7.0	9.6	$22.00	$31.95	$395.48	$69.65	$129.47	$233.38	$0.00	$881.93	$20.49	2.4%
AnnAvg	0.40	1,568	500	1,068	5.4	5.4	0.0	$22.00	$31.95	$68.24	$53.53	$0.00	$54.70	$0.00	$230.42	$15.12	7.0%
SGSAvg	0.42	1,886	500	1,386	6.2	6.2	0.0	$22.00	$31.95	$88.53	$61.79	$0.00	$65.78	$0.00	$270.05	$14.69	5.8%

Medium General Service RATE MGS

WINTER

	BILL IMPACTS CURRENT RATES (GS-10)									
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.05700	$0.07900	$0.031532	$0.00682	
Xsm	9,000	500	8,500	$15.50	$28.50	$671.50	$283.79	$61.38	$1,060.67
Small	14,000	500	13,500	$15.50	$28.50	$1,066.50	$441.45	$95.48	$1,647.43
Medium	23,000	500	22,500	$15.50	$28.50	$1,777.50	$725.24	$156.86	$2,703.60
Large	37,000	500	36,500	$15.50	$28.50	$2,883.50	$1,166.68	$252.34	$4,346.52
XLg	45,000	500	44,500	$15.50	$28.50	$3,515.50	$1,418.94	$306.90	$5,285.34
AnnAvg	20,468	500	19,968	$15.50	$28.50	$1,577.50	$645.41	$139.59	$2,406.50
MGSAvg	17,563	500	17,063	$15.50	$28.50	$1,347.99	$553.80	$119.78	$2,065.57

	BILL IMPACTS PROPOSED RATES (MGS)									
	kW	kWh	Basic Service Charge	kW Charge	Delivery Charge kWh	Base Fuel	PPFAC	Net Bill		
			$40.00	$5.00	$0.06779	$0.032608	$0.00000			
Load Factor	35%								$ Change	% Change
Xsm	34	9,000	$40.00	$171.53	$610.11	$293.47	$0.00	$1,115.11	$54.44	5.1%
Small	53	14,000	$40.00	$266.82	$949.06	$456.51	$0.00	$1,712.39	$64.96	3.9%
Medium	88	23,000	$40.00	$438.35	$1,559.17	$749.98	$0.00	$2,787.50	$83.90	3.1%
Large	141	37,000	$40.00	$705.17	$2,508.23	$1,206.50	$0.00	$4,459.90	$113.38	2.6%
XLg	172	45,000	$40.00	$857.64	$3,050.55	$1,467.36	$0.00	$5,415.55	$130.21	2.5%
AnnAvg	78	20,468	$40.00	$390.10	$1,387.55	$667.43	$0.00	$2,485.08	$78.58	3.3%
MGSAvg	67	17,563	$40.00	$334.73	$1,190.61	$572.70	$0.00	$2,138.04	$72.47	3.5%

Medium General Service RATE MGS

SUMMER

BILL IMPACTS CURRENT RATES (GS-10)

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery		Base Fuel	PPFAC	Net Bill
		500	>500		500	>500			
				$15.50	$0.07700	$0.09780	$0.035111	$0.00682	
Xsm	14,000	500	13,500	$15.50	$38.50	$1,320.30	$491.55	$95.48	$1,961.33
Small	19,000	500	18,500	$15.50	$38.50	$1,809.30	$667.11	$129.58	$2,659.99
Medium	32,000	500	31,500	$15.50	$38.50	$3,080.70	$1,123.55	$218.24	$4,476.49
Large	50,000	500	49,500	$15.50	$38.50	$4,841.10	$1,755.55	$341.00	$6,991.65
XLg	62,000	500	61,500	$15.50	$38.50	$6,014.70	$2,176.88	$422.84	$8,668.42
AnnAvg	20,468	500	19,968	$15.50	$38.50	$1,952.90	$718.66	$139.59	$2,865.15
MGSAvg	24,544	500	24,044	$15.50	$38.50	$2,351.53	$861.78	$167.39	$3,434.70

BILL IMPACTS PROPOSED RATES (MGS)

	kW	kWh	Basic Service Charge	kW Charge	Delivery Charge kWh	Base Fuel	PPFAC	Net Bill	$ Change	% Change
			$40.00	$6.75	$0.08079	$0.035691	$0.00000			
Load Factor	35%									
Xsm	53	14,000	$40.00	$360.21	$1,131.06	$499.67	$0.00	$2,030.94	$69.61	3.5%
Small	72	19,000	$40.00	$488.85	$1,535.01	$678.13	$0.00	$2,741.99	$82.00	3.1%
Medium	122	32,000	$40.00	$823.33	$2,585.28	$1,142.11	$0.00	$4,590.72	$114.23	2.6%
Large	191	50,000	$40.00	$1,286.45	$4,039.50	$1,784.55	$0.00	$7,150.50	$158.85	2.3%
XLg	236	62,000	$40.00	$1,595.20	$5,008.98	$2,212.84	$0.00	$8,857.02	$188.60	2.2%
AnnAvg	78	20,468	$40.00	$526.63	$1,653.63	$730.53	$0.00	$2,950.79	$85.64	3.0%
MGSAvg	94	24,544	$40.00	$631.50	$1,982.94	$876.01	$0.00	$3,530.45	$95.75	2.8%

MEDIUM GENERAL SERVICE TIME OF USE

Winter

BILL IMPACTS CURRENT RATES (GS-76)

	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		500	>500					
On-Peak	0.24			$17.50	$0.08140	$0.032893	$0.00682	
Off-Peak	0.76				$0.06490	$0.027092		
Xsm	13,000	500	12,500	$17.50	$896.00	$370.58	$88.66	$1,372.74
Small	21,000	500	20,500	$17.50	$1,447.38	$598.63	$143.22	$2,206.73
Medium	29,000	500	28,500	$17.50	$1,998.77	$826.69	$197.78	$3,040.74
Large	39,000	500	38,500	$17.50	$2,688.00	$1,111.75	$265.98	$4,083.23
XLg	48,000	500	47,500	$17.50	$3,308.30	$1,368.31	$327.36	$5,021.47
AnnAvg	25,332	500	24,832	$17.50	$1,745.94	$722.12	$172.76	$2,658.32
MGSAvg	17,563	500	17,063	$17.50	$1,210.51	$500.66	$119.78	$1,848.45

BILL IMPACTS PROPOSED RATES (MGS TOU)

	kW	kWh	Basic Service Charge	Demand Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
Load Factor	63%									
On-Peak		0.24	$40.00	$3.35	$0.11080	$0.038010	$0.00000			
Off-Peak		0.76			$0.06010	$0.025655				
Xsm	28	13,000	$40.00	$92.59	$942.00	$372.68	$0.00	$1,447.27	$74.53	5.4%
Small	45	21,000	$40.00	$149.57	$1,521.69	$602.01	$0.00	$2,313.27	$106.54	4.8%
Medium	62	29,000	$40.00	$206.55	$2,101.38	$831.35	$0.00	$3,179.28	$138.54	4.6%
Large	83	39,000	$40.00	$277.77	$2,826.00	$1,118.03	$0.00	$4,261.80	$178.57	4.4%
XLg	102	48,000	$40.00	$341.87	$3,478.15	$1,376.03	$0.00	$5,236.05	$214.58	4.3%
AnnAvg	54	25,332	$40.00	$180.42	$1,835.58	$726.19	$0.00	$2,782.19	$123.87	4.7%
MGSAvg	37	17,563	$40.00	$125.09	$1,272.66	$503.49	$0.00	$1,941.24	$92.79	5.0%

MEDIUM GENERAL SERVICE TIME OF USE

Summer

	BILL IMPACTS CURRENT RATES (GS-76)							
	kWh	Delivery (kWh) TIERS		Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
		500	>500					
On-Peak	0.20			$17.50	$0.09910	$0.050669	$0.00682	
Off-Peak	0.80				$0.08490	$0.026679		
Xsm	18,000	500	17,500	$17.50	$1,580.16	$568.01	$122.76	$2,288.43
Small	27,000	500	26,500	$17.50	$2,370.24	$852.01	$184.14	$3,423.89
Medium	37,000	500	36,500	$17.50	$3,248.11	$1,167.57	$252.34	$4,685.52
Large	50,000	500	49,500	$17.50	$4,389.34	$1,577.80	$341.00	$6,325.64
XLg	65,000	500	64,500	$17.50	$5,706.14	$2,051.14	$443.30	$8,218.08
AnnAvg	25,332	500	24,832	$17.50	$2,223.79	$799.37	$172.76	$3,213.42
MGSAvg	24,544	500	24,044	$17.50	$2,154.67	$774.52	$167.39	$3,114.08

	BILL IMPACTS PROPOSED RATES (MGS TOU)									
	kW	kWh	Basic Service Charge	Demand Charge	Delivery	Base Fuel	PPFAC	Net Bill		
Load Factor	63%									
On-Peak		0.20	$40.00	$7.75	$0.11080	$0.071322	$0.00000			
Off-Peak		0.80			$0.06010	$0.025609			$ Change	% Change
Xsm	38	18,000	$40.00	$296.59	$1,267.32	$628.24	$0.00	$2,232.15	-$56.28	-2.5%
Small	57	27,000	$40.00	$444.88	$1,900.99	$942.36	$0.00	$3,328.23	-$95.66	-2.8%
Medium	79	37,000	$40.00	$609.65	$2,605.05	$1,291.38	$0.00	$4,546.08	-$139.44	-3.0%
Large	106	50,000	$40.00	$823.86	$3,520.34	$1,745.10	$0.00	$6,129.30	-$196.34	-3.1%
XLg	138	65,000	$40.00	$1,071.01	$4,576.45	$2,268.63	$0.00	$7,956.09	-$261.99	-3.2%
AnnAvg	54	25,332	$40.00	$417.39	$1,783.53	$884.13	$0.00	$3,125.05	-$88.37	-2.8%
MGSAvg	52	24,544	$40.00	$404.42	$1,728.09	$856.65	$0.00	$3,029.16	-$84.92	-2.7%

Large General Service Rate LGS-13

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
				$775.00	$15.25	$0.01340	$0.031532	$0.00682	
Xsm	0.55	200	58,000	$775.00	$3,050.00	$777.20	$1,828.86	$395.56	$6,826.62
Small	0.55	223	91,360	$775.00	$3,404.79	$1,224.22	$2,880.76	$623.08	$8,907.85
Medium	0.55	427	174,840	$775.00	$6,515.91	$2,342.86	$5,513.05	$1,192.41	$16,339.23
Large	0.55	725	296,700	$775.00	$11,057.37	$3,975.78	$9,355.54	$2,023.49	$27,187.18
XLg	0.55	1088	445,200	$775.00	$16,591.64	$5,965.68	$14,038.05	$3,036.26	$40,406.63
AnnAvg	0.55	395	161,792	$775.00	$6,029.62	$2,168.01	$5,101.61	$1,103.42	$15,177.66
LGSAvg	0.55	366	149,663	$775.00	$5,577.62	$2,005.48	$4,719.17	$1,020.70	$14,097.97

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$950.00	$17.40	$0.01430	$0.032608	$0.00000			
Xsm	0.55	200	58,000	$950.00	$3,480.00	$829.40	$1,891.26	$0.00	$7,150.66	$324.04	4.7%
Small	0.55	223	91,360	$950.00	$3,884.81	$1,306.45	$2,979.07	$0.00	$9,120.33	$212.48	2.4%
Medium	0.55	427	174,840	$950.00	$7,434.55	$2,500.21	$5,701.18	$0.00	$16,585.94	$246.71	1.5%
Large	0.55	725	296,700	$950.00	$12,616.28	$4,242.81	$9,674.79	$0.00	$27,483.88	$296.70	1.1%
XLg	0.55	1,088	445,200	$950.00	$18,930.79	$6,366.36	$14,517.08	$0.00	$40,764.23	$357.60	0.9%
AnnAvg	0.55	395	161,792	$950.00	$6,879.70	$2,313.62	$5,275.70	$0.00	$15,419.02	$241.36	1.6%
LGSAvg	0.55	366	149,663	$950.00	$6,363.97	$2,140.18	$4,880.21	$0.00	$14,334.36	$236.39	1.7%

Large General Service Rate LGS-13

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
				$775.00	$15.25	$0.01920	$0.035111	$0.00682	
Xsm	0.55	200	72,960	$775.00	$3,050.00	$1,400.83	$2,561.70	$497.59	$8,285.12
Small	0.55	282	115,584	$775.00	$4,307.57	$2,219.21	$4,058.27	$788.28	$12,148.33
Medium	0.55	521	213,300	$775.00	$7,949.23	$4,095.36	$7,489.18	$1,454.71	$21,763.48
Large	0.55	815	333,600	$775.00	$12,432.55	$6,405.12	$11,713.03	$2,275.15	$33,600.85
XLg	0.55	1230	503,200	$775.00	$18,753.18	$9,661.44	$17,667.86	$3,431.82	$50,289.30
AnnAvg	0.55	395	161,792	$775.00	$6,029.62	$3,106.40	$5,680.66	$1,103.42	$16,695.10
LGSAvg	0.55	437	178,619	$775.00	$6,656.74	$3,429.48	$6,271.49	$1,218.18	$18,350.89

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$950.00	$17.40	$0.01853	$0.035691	$0.00000			
Xsm	0.55	200	72,960	$950.00	$3,480.00	$1,351.95	$2,604.02	$0.00	$8,385.97	$100.85	1.2%
Small	0.55	282	115,584	$950.00	$4,914.86	$2,141.77	$4,125.31	$0.00	$12,131.94	-$16.39	-0.1%
Medium	0.55	521	213,300	$950.00	$9,069.94	$3,952.45	$7,612.89	$0.00	$21,585.28	-$178.20	-0.8%
Large	0.55	815	333,600	$950.00	$14,185.34	$6,181.61	$11,906.52	$0.00	$33,223.47	-$377.38	-1.1%
XLg	0.55	1,230	503,200	$950.00	$21,397.07	$9,324.30	$17,959.71	$0.00	$49,631.08	-$658.22	-1.3%
AnnAvg	0.55	395	161,792	$950.00	$6,879.70	$2,998.00	$5,774.50	$0.00	$16,602.20	-$92.90	-0.6%
LGSAvg	0.55	437	178,619	$950.00	$7,595.23	$3,309.81	$6,375.08	$0.00	$18,230.12	-$120.77	-0.7%

Large General Service Time of Use Rate LGS-85

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		24.3%	$950.00	$11.59	$0.00300	$0.032893	$0.00682	
	Off-Peak		75.7%		$9.10	$0.00050	$0.027092		
Xsm	0.58	288	124,480	$950.00	$5,443.40	$137.85	$3,547.85	$848.95	$10,928.05
Small	0.58	390	168,111	$950.00	$7,351.33	$186.16	$4,791.38	$1,146.51	$14,425.38
Medium	0.58	476	205,552	$950.00	$8,988.61	$227.63	$5,858.52	$1,401.86	$17,426.62
Large	0.58	621	267,929	$950.00	$11,716.31	$296.70	$7,636.35	$1,827.28	$22,426.64
XLg	0.58	827	356,983	$950.00	$15,610.54	$395.32	$10,174.50	$2,434.62	$29,564.98
AnnAvg	0.58	448	193,169	$950.00	$8,447.12	$213.91	$5,505.59	$1,317.41	$16,434.03
LGSAvg	0.58	347	149,663	$950.00	$6,544.64	$165.74	$4,265.60	$1,020.70	$12,946.68

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
	On-Peak		24.3%	$950.00	$18.50	$0.00710	$0.038010	$0.00000			
	Off-Peak		75.7%			$0.00125	$0.025655				
Xsm	0.58	288	124,480	$950.00	$5,336.67	$332.52	$3,567.19	$0.00	$10,186.38	-$741.67	-6.8%
Small	0.58	390	168,111	$950.00	$7,207.18	$449.07	$4,817.50	$0.00	$13,423.75	-$1,001.63	-6.9%
Medium	0.58	476	205,552	$950.00	$8,812.37	$549.09	$5,890.45	$0.00	$16,201.91	-$1,224.71	-7.0%
Large	0.58	621	267,929	$950.00	$11,486.57	$715.72	$7,677.97	$0.00	$20,830.26	-$1,596.38	-7.1%
XLg	0.58	827	356,983	$950.00	$15,304.45	$953.60	$10,229.95	$0.00	$27,438.00	-$2,126.98	-7.2%
AnnAvg	0.58	448	193,169	$950.00	$8,281.49	$516.01	$5,535.59	$0.00	$15,283.09	-$1,150.94	-7.0%
LGSAvg	0.58	347	149,663	$950.00	$6,416.31	$399.79	$4,288.85	$0.00	$12,054.95	-$891.73	-6.9%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Large General Service Time of Use Rate LGS-85

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		19.7%	$950.00	$14.55	$0.00860	$0.050669	$0.00682	
	Off-Peak		80.3%		$10.92	$0.00600	$0.026679		
Xsm	0.58	317	136,680	$950.00	$7,375.63	$890.15	$4,293.00	$932.16	$14,440.94
Small	0.58	436	188,009	$950.00	$10,145.48	$1,224.44	$5,905.20	$1,282.22	$19,507.34
Medium	0.58	536	231,233	$950.00	$12,477.97	$1,505.94	$7,262.82	$1,577.01	$23,773.74
Large	0.58	736	317,688	$950.00	$17,143.31	$2,068.99	$9,978.30	$2,166.63	$32,307.23
XLg	0.58	976	420,961	$950.00	$22,716.21	$2,741.57	$13,222.01	$2,870.95	$42,500.74
AnnAvg	0.58	448	193,169	$950.00	$10,423.93	$1,258.04	$6,067.27	$1,317.41	$20,016.65
LGSAvg	0.58	414	178,619	$950.00	$9,638.76	$1,163.28	$5,610.26	$1,218.18	$18,580.48

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
	On-Peak		19.7%	$950.00	$22.15	$0.01854	$0.071322	$0.00000			
	Off-Peak		80.3%			$0.01270	$0.025609				
Xsm	0.58	317	136,680	$950.00	$7,015.81	$1,893.22	$4,732.17	$0.00	$14,591.20	$150.26	1.0%
Small	0.58	436	188,009	$950.00	$9,650.54	$2,604.20	$6,509.30	$0.00	$19,714.04	$206.70	1.1%
Medium	0.58	536	231,233	$950.00	$11,869.23	$3,202.92	$8,005.81	$0.00	$24,027.96	$254.22	1.1%
Large	0.58	736	317,688	$950.00	$16,306.98	$4,400.45	$10,999.07	$0.00	$32,656.50	$349.27	1.1%
XLg	0.58	976	420,961	$950.00	$21,608.00	$5,830.93	$14,574.62	$0.00	$42,963.55	$462.81	1.1%
AnnAvg	0.58	448	193,169	$950.00	$9,915.41	$2,675.68	$6,687.95	$0.00	$20,229.04	$212.39	1.1%
LGSAvg	0.58	414	178,619	$950.00	$9,168.54	$2,474.13	$6,184.19	$0.00	$18,776.86	$196.38	1.1%

Large Power Service Rate LPS-90

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		23.1%	$2,000.00	$15.49	$0.00750	$0.029581	$0.00682	
	Off-Peak		76.9%			$0.00710	$0.024352		
Xsm	0.80	4,460	2,654,563	$2,000.00	$69,084.65	$19,092.82	$67,852.15	$18,104.12	$176,133.74
Small	0.80	7,130	4,243,957	$2,000.00	$110,448.41	$30,524.46	$108,477.97	$28,943.79	$280,394.63
Medium	0.80	13,369	7,957,222	$2,000.00	$207,085.63	$57,231.93	$203,391.15	$54,268.25	$523,976.96
Large	0.80	16,093	9,578,605	$2,000.00	$249,281.91	$68,893.65	$244,834.63	$65,326.09	$630,336.28
XLg	0.80	17,404	10,359,070	$2,000.00	$269,593.40	$74,507.11	$264,783.76	$70,648.86	$681,533.13
AnnAvg	0.80	9,398	5,593,406	$2,000.00	$145,567.63	$40,230.30	$142,970.65	$38,147.03	$368,915.61
LPSAvg	0.80	8,725	5,193,148	$2,000.00	$135,150.99	$37,351.47	$132,739.84	$35,417.27	$342,659.57

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
	On-Peak		23.1%	$10,000.00	$17.00	$0.00700	$0.033550	$0.00000			
	Off-Peak		76.9%			$0.00700	$0.025660				
Xsm	0.80	4,460	2,654,563	$10,000.00	$75,819.17	$18,581.94	$72,956.96	$0.00	$177,358.07	$1,224.33	0.7%
Small	0.80	7,130	4,243,957	$10,000.00	$121,215.17	$29,707.70	$116,639.24	$0.00	$277,562.11	-$2,832.52	-1.0%
Medium	0.80	13,369	7,957,222	$10,000.00	$227,272.81	$55,700.55	$218,693.16	$0.00	$511,666.52	-$12,310.44	-2.3%
Large	0.80	16,093	9,578,605	$10,000.00	$273,582.47	$67,050.24	$263,254.61	$0.00	$613,887.32	-$16,448.96	-2.6%
XLg	0.80	17,404	10,359,070	$10,000.00	$295,873.98	$72,513.49	$284,704.60	$0.00	$663,092.07	-$18,441.06	-2.7%
AnnAvg	0.80	9,398	5,593,406	$10,000.00	$159,757.89	$39,153.84	$153,726.96	$0.00	$362,638.69	-$6,276.92	-1.7%
LPSAvg	0.80	8,725	5,193,148	$10,000.00	$148,325.81	$36,352.04	$142,726.44	$0.00	$337,404.29	-$5,255.28	-1.5%

Large Power Service Rate LPS-90

Summer

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill
	On-Peak		17.0%	$2,000.00	$20.49	$0.00690	$0.045568	$0.00682	
	Off-Peak		83.0%			$0.00650	$0.023985		
Xsm	0.80	4527	2,694,604	$2,000.00	$92,762.83	$17,698.42	$74,530.92	$18,377.20	$205,369.37
Small	0.80	8371	4,982,527	$2,000.00	$171,525.50	$32,725.72	$137,813.33	$33,980.83	$378,045.38
Medium	0.80	14825	8,823,900	$2,000.00	$303,766.32	$57,956.23	$244,063.10	$60,179.00	$667,964.65
Large	0.80	19858	11,819,577	$2,000.00	$406,893.70	$77,632.12	$326,921.50	$80,609.52	$894,056.84
XLg	0.80	21021	12,511,438	$2,000.00	$430,711.30	$82,176.33	$346,057.91	$85,328.01	$946,273.55
AnnAvg	0.80	9398	5,593,406	$2,000.00	$192,555.25	$36,738.03	$154,709.82	$38,147.03	$424,150.13
LPSAvg	0.80	10375	6,174,912	$2,000.00	$212,573.82	$40,557.42	$170,793.88	$42,112.90	$468,038.02

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Demand (kW)	Delivery (kWh)	Base Fuel	PPFAC	Net Bill	$ Change	% Change
	On-Peak		17.0%	$10,000.00	$21.55	$0.00700	$0.052350	$0.00000			
	Off-Peak		83.0%			$0.00700	$0.025760				
Xsm	0.80	4,527	2,694,604	$10,000.00	$97,561.69	$18,862.23	$81,610.72	$0.00	$208,034.64	$2,665.27	1.3%
Small	0.80	8,371	4,982,527	$10,000.00	$180,398.95	$34,877.69	$150,904.41	$0.00	$376,181.05	-$1,864.33	-0.5%
Medium	0.80	14,825	8,823,900	$10,000.00	$319,480.92	$61,767.30	$267,247.01	$0.00	$658,495.23	-$9,469.42	-1.4%
Large	0.80	19,858	11,819,577	$10,000.00	$427,943.35	$82,737.04	$357,976.25	$0.00	$878,656.64	-$15,400.20	-1.7%
XLg	0.80	21,021	12,511,438	$10,000.00	$452,993.09	$87,580.07	$378,930.45	$0.00	$929,503.61	-$16,769.94	-1.8%
AnnAvg	0.80	9,398	5,593,406	$10,000.00	$202,516.62	$39,153.84	$169,405.93	$0.00	$421,076.39	-$3,073.74	-0.7%
LPSAvg	0.80	10,375	6,174,912	$10,000.00	$223,570.81	$43,224.38	$187,017.84	$0.00	$463,813.03	-$4,224.99	-0.9%

Traffic Signal & Street Lighting

WINTER

	BILL IMPACTS CURRENT RATES					
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
			$0.04760	$0.031532	$0.00682	
Xsm	169		$8.04	$5.33	$1.15	$14.52
Small	1,180		$56.17	$37.21	$8.05	$101.43
Medium	4,370		$208.01	$137.79	$29.80	$375.60
Large	7,560		$359.86	$238.38	$51.56	$649.80
XLg	9,300		$442.68	$293.25	$63.43	$799.36
AnnAvg	2,484		$118.25	$78.33	$16.94	$213.52
TSSLAvg	2,687		$127.89	$84.72	$18.32	$230.93

	BILL IMPACTS PROPOSED RATES							
	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill		
			$0.06011	$0.032608	$0.00000			
							$ Change	% Change
Xsm	169		$10.16	$5.51	$0.00	$15.67	$1.15	7.9%
Small	1,180		$70.93	$38.48	$0.00	$109.41	$7.98	7.9%
Medium	4,370		$262.69	$142.50	$0.00	$405.19	$29.59	7.9%
Large	7,560		$454.45	$246.52	$0.00	$700.97	$51.17	7.9%
XLg	9,300		$559.04	$303.25	$0.00	$862.29	$62.93	7.9%
AnnAvg	2,484		$149.33	$81.00	$0.00	$230.33	$16.81	7.9%
TSSLAvg	2,687		$161.50	$87.61	$0.00	$249.11	$18.18	7.9%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

Traffic Signal & Street Lighting

Summer

BILL IMPACTS CURRENT RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill
			$0.04760	$0.035111	$0.00682	
Xsm	170		$8.09	$5.97	$1.16	$15.22
Small	1,020		$48.55	$35.81	$6.96	$91.32
Medium	3,599		$171.31	$126.36	$24.55	$322.22
Large	6,200		$295.12	$217.69	$42.28	$555.09
XLg	7,500		$357.00	$263.33	$51.15	$671.48
AnnAvg	2,484		$118.25	$87.22	$16.94	$222.41
TSSLAvg	2,204		$104.93	$77.40	$15.03	$197.36

BILL IMPACTS PROPOSED RATES

	kWh	Basic Service Charge	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
			$0.06011	$0.035691	$0.00000			
Xsm	170		$10.22	$6.07	$0.00	$16.29	$1.07	7.0%
Small	1,020		$61.31	$36.40	$0.00	$97.71	$6.39	7.0%
Medium	3,599		$216.34	$128.45	$0.00	$344.79	$22.57	7.0%
Large	6,200		$372.69	$221.28	$0.00	$593.97	$38.88	7.0%
XLg	7,500		$450.84	$267.68	$0.00	$718.52	$47.04	7.0%
AnnAvg	2,484		$149.33	$88.66	$0.00	$237.99	$15.58	7.0%
TSSLAvg	2,204		$132.51	$78.68	$0.00	$211.19	$13.83	7.0%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

DISTRIBUTION ID 5402

Area Lighting

	Current	Proposed
100OH	$8.19	$10.55
100UG	$23.72	$30.55
250OH	$12.29	$15.83
400OH	$18.70	$24.09
55OH	$8.19	$10.55
55UG	$23.72	$30.55
70UG	$23.72	$30.55
POLE	$2.86	$3.68
Base Power		
100OH	$1.34	$1.36
100UG	$1.34	$1.36
250OH	$3.36	$3.42
400OH	$5.38	$5.47
55OH	$0.85	$0.86
55UG	$0.85	$0.86
70UG	$0.94	$0.96
PPFAC	$0.00682	$0.00000

BILL IMPACTS CURRENT RATES

		kWh	Delivery	Base Fuel	PPFAC	Net Bill
					$0.00682	
55OH	Xsm	93	$8.19	$0.85	$0.63	$9.67
70UG	Small	124	$23.72	$0.94	$0.85	$25.51
100UG	Medium	215	$23.72	$1.34	$1.47	$26.53
250OH	Large	720	$12.29	$3.36	$4.91	$20.56
400OH	XLg	1,339	$18.70	$5.38	$9.13	$33.21
	Pole	0	$2.86	$0.00	$0.00	$2.86
100OH	ALAvg	316	$8.19	$1.34	$2.15	$11.68

BILL IMPACTS PROPOSED RATES

	kWh	Delivery	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$0.00000			
Xsm	93	$10.55	$0.86	$0.00	$11.41	$1.74	18.0%
Small	124	$30.55	$0.96	$0.00	$31.51	$6.00	23.5%
Medium	215	$30.55	$1.36	$0.00	$31.91	$5.38	20.3%
Large	720	$15.83	$3.42	$0.00	$19.25	-$1.31	-6.4%
XLg	1,339	$24.09	$5.47	$0.00	$29.56	-$3.65	-11.0%
Pole	0	$3.68	$0.00	$0.00	$3.68	$0.82	28.7%
ALAvg	316	$10.55	$1.36	$0.00	$11.91	$0.23	2.0%

Exhibit CAJ-RJ-2

Tucson Electric Power
Bill Impacts
Test Year Ending June 30, 2015

Class Description	Customer Counts 6/1/16	New Summer Monthly Bill A	New Winter Monthly Bill D	New Annual Bill	Annual Bill Change	$ Change from Standard Tariff	Revised Percent Change to	Monthly $ Change in Bill	Lifeline Discount
Residential Service	344,594	$140	$95	$1,365	$98		7.7%	$8.15	
Residential Lifeline R-01LL	7,856	$125	$80	$1,185	$26	($180)	2.2%	$2.15	$15.00
Residential Lifeline R-04-01F	363	$110	$65	$1,005	$76	($360)	8.2%	$6.34	$30.00
Residential Lifeline R-05-01F	871	$125	$80	$1,185	$110	($180)	10.2%	$9.14	$15.00
Residential Lifeline R-06-01F	4,538	$122	$77	$1,149	$101	($216)	9.6%	$8.38	$18.00
Residential Lifeline R-08-01F	514	$100	$55	$885	$102	($480)	13.1%	$8.54	$40.00
Residential R-201A	11,465	$131	$90	$1,288	$90	($77)	7.5%	$7.52	
Residential Lifeline R-201AL	239	$116	$75	$1,108	$18	($257)	1.7%	$1.52	$15.00
Residential Lifeline 06-201AF	240	$113	$72	$1,072	$102	($293)	10.5%	$8.48	$18.00
Residential Lifeline 08-201AF	9	$91	$50	$808	$76	($557)	10.4%	$6.36	$40.00
Residential TOU R-80	7,857	$133	$88	$1,281	$157	($83)	14.0%	$13.12	
Residential Lifeline TOU R-80LL	113	$118	$73	$1,101	$85	($263)	8.4%	$7.12	$15.00
Residential Lifeline R-04-21F	2	$103	$58	$921	$100	($443)	12.2%	$8.33	$30.00
Residential Lifeline R-05-21F	1	$118	$73	$1,101	$145	($263)	15.1%	$12.04	$15.00
Residential Lifeline R-06-21F	15	$115	$70	$1,065	$164	($299)	18.2%	$13.69	$18.00
Residential Lifeline R-08-21F	6	$93	$48	$801	$112	($563)	16.2%	$9.31	$40.00
Residential Lifeline R-04-70F	4	$103	$58	$921	$42	($443)	4.8%	$3.54	$30.00
Residential Lifeline R-05-70F	7	$118	$73	$1,101	$103	($263)	10.4%	$8.62	$15.00
Residential Lifeline R-06-70F	50	$118	$73	$1,101	$127	($263)	13.0%	$10.59	$15.00
Residential Lifeline R-08-70F	15	$93	$48	$801	$76	($563)	10.5%	$6.33	$40.00
Residential TOU Super Peak	220	$133	$88	$1,281	$197	($83)	18.1%	$16.40	
Residential Lifeline TOU Super Peak	7	$118	$73	$1,101	$125	($263)	12.8%	$10.40	$15.00
Residential R-201B	613	$126	$84	$1,214	$173	($151)	16.7%	$14.46	
Residential Lifeline R-201BL	4	$111	$69	$1,034	$101	($331)	10.9%	$8.46	$15.00
Residential Lifeline 06-201BF	4	$113	$70	$1,051	$164	($314)	18.5%	$13.66	$15.00
General Service	35,624	$278	$177	$2,628	$153		6.2%	$12.72	
SGS Time of Use	1,140	$271	$167	$2,522	$147	($105)	6.2%	$12.23	
General Service R-10 Municipal	828	$278	$177	$2,628	$530	$0	25.3%	$44.20	
Mobile Home Park Service	252	$1,871	$1,535	$20,099	$1,735		9.4%	$144.56	
Municipal Water Pumping Service	424	$1,951	$1,165	$17,910	$860		5.0%	$71.68	
Municipal Interruptible WP Service	157	$1,438	$870	$13,280	$861	($4,631)	6.9%	$71.79	
Medium General Service		$3,530	$2,138	$32,619	$986		3.1%	$82.17	
Medium General Service TOU		$3,029	$1,941	$28,734	$225	($3,884)	0.8%	$18.74	
Large General Service	433	$18,230	$14,334	$191,491	$1,051		0.6%	$87.57	
Large General Service TOU	128	$18,777	$12,055	$178,269	($5,260)	($13,222)	-2.9%	($438.35)	
Large Power Service	19	$463,813	$337,404	$4,680,895	($57,912)		-1.2%	($4,825.99)	
Traffic Signal& Street Light Service	5,897	$211	$249	$2,800	$196		7.5%	$16.37	

REJOINDER TESTIMONY OF
RICHARD D. BACHMEIER

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of

Richard D. Bachmeier

on Behalf of

Tucson Electric Power Company

September 1, 2016

TABLE OF CONTENTS

EXHIBITS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Richard D. Bachmeier and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am a Principal Rate Designer for Tucson Electric Power Company ("TEP" or the "Company"). My responsibilities include developing rates, charges, and terms of service for TEP and UNS Electric rate offerings, performing cost of service analyses, and providing general rate and pricing support for existing and new programs.

Q. Did you file Rebuttal Testimony in this proceeding?

A. Yes.

Q. What issues do you address in your Rejoinder Testimony?

A. I am presenting the Company's proposed optional residential and small general service ("SGS") three-part demand rates and charges for its Rejoinder case. I also address the testimony of Intervenor witnesses Lon Huber of the Residential Utility Consumer Office ("RUCO") and Brendon Baatz of Southwest Energy Efficiency Project ("SWEEP") and Western Resource Advocates ("WRA") on the topics of utility fixed cost recovery and inclining block rates. Finally, I specifically respond to the Surrebuttal Testimony of SOLON Corporation ("SOLON") witness Mr. Seibel, in particular, to address his comments related to my Rebuttal Testimony and TEP's proposed rate tariff applicability.

II. TEP'S REJOINDER PROPOSALS FOR THE RESIDENTIAL AND SGS THREE-PART RATE OPTIONS.

Q. Has TEP changed any of its proposals for residential and SGS three-part rates for Rejoinder?

A. Yes. TEP witness Mr. Jones is sponsoring the Company's Rejoinder proposals for residential and SGS three-part rates. The Company is proposing the following changes to its Rebuttal position:

- Monthly Basic Service Charges for three-part rates are $12.00 per month for residential and $22.00 per month for SGS. These charges are reduced from $15.00 and $27.00 for two-part, non-TOU, residential and SGS service, respectively.
- Revised energy and demand charges are based on the Company's revenue requirement resulting from the Settlement Agreement in this proceeding.
- Billing demand is to be defined as the maximum one-hour average kW during the on-peak periods as those periods are defined in the Company's applicable TOU tariffs.

Q. Please describe the Company's Rejoinder proposal for residential three-part rates.

A. In Rejoinder, the Company is proposing three-part RES-D and RES TOU-D rates with the following elements:

- A monthly Basic Service Charge of $12.00.
- Demand charges of $8.75/kW for the first 7 kW of billing demand and $12.50/kW for all billing demand greater than 7 kW with billing demand defined as the maximum one-hour average kW during on-peak periods in the billing month.
- An Energy Delivery Charge of $0.03174/kWh for all billing kWh.

- All other charges equal to those in the Company's equivalent two-part tariff for RES and RES-TOU service.

Q. Have you performed any bill comparison analyses for the three-part residential rates the Company is proposing in Rejoinder?

A. Yes, I am providing residential bill comparisons for full requirements customers at 45 usage levels from 100 kWh to 4,500 kWh per month and for every one of the 16,962 observations in the residential load profile sample described in my Rebuttal testimony.[1] In addition, the table below summarizes bill impacts, excluding miscellaneous charges and taxes, for full-requirements residential customers using 500, 900, 1,200, and 1,500 kWh per month under the Company's proposed residential two-part RES and three-part RES-D.

Average Monthly Usage	On Peak kW Load Factor	Billing kW	Average Monthly Bill		
			RES	RES-D	Difference
500 kWh	23.7%	2.89	$63.85	$70.11	$6.26
900 kWh	28.2%	4.37	$109.24	$109.30	$0.06
1,200 kWh	30.7%	5.35	$143.29	$137.57	($5.72)
1,500 kWh	32.8%	6.26	$177.34	$165.23	($12.11)

Q. Please describe the Company's Rejoinder proposal for SGS three-part rates.

A. In Rejoinder, the Company is proposing three-part basic SGS and SGS TOU rates with the following elements:

- A monthly Basic Service Charge of $22.00.
- Demand charges of $9.95/kW for the first 7 kW of billing demand and $13.50/kW for all billing demand greater than 7 kW with billing demand

[1] See "2015 TEP RES Dem Rate_rj-FINAL.xlsx" submitted with Company's Rejoinder workpapers. The original sample used for Rebuttal had 16,963 observations, but one observation was eliminated after changing the TOU periods.

defined as the maximum one-hour average kW during on-peak periods in the billing month.

- Energy Delivery Charges of $0.06389/kWh for all summer billing kWh and $0.05389/kWh for all winter billing kWh.
- All other charges equal to those in the Company's equivalent two-part tariff for SGS and SGS-TOU service.

Q. Has TEP performed any bill comparison analyses for the three-part SGS rates the Company is proposing in Rejoinder?

A. Yes, I am providing bill comparisons for full requirements SGS customers at 53 usage levels from 150 kWh to 20,000 kWh per month and for every one of the 5,691 observations in the SGS load profile sample.[2] In addition, the table below presents monthly bill comparisons, excluding miscellaneous charges and taxes, for SGS customers using 300, 1,200, 2,400, and 5,000 kWh per month.

Average Monthly Usage	On Peak kW Load Factor	Billing kW	Average Monthly Bill		
			SGS	SGS-D	Difference
300 kWh	27.5%	1.49	$59.55	$64.41	$4.86
1,200 kWh	37.6%	4.38	$170.11	$175.92	$5.81
2,400 kWh	43.9%	7.49	$322.44	$318.94	($3.50)
5,000 kWh	51.7%	13.24	$652.49	$635.63	($16.86)

[2] See "2015 TEP SGS Dem Rate_rj-FINAL.xlsx" submitted with Company's Rejoinder workpapers.

III. REGULATION, COMPETITION, AND INCLINING BLOCK RATES.

Q. In their Direct and/or Surrebuttal testimonies, some parties to this proceeding express variations of the concept that utility regulation should be used to replicate, or serve as a substitute for, a competitive market.[3] Do you agree?

A. Yes, but I believe that some intervenors have stretched this position beyond its applicability. Utility rate regulation was originally conceived as method of setting rates in a market characterized by a natural monopoly to be more consistent with those that would result in a competitive market. In economic theory, a market characterized by monopoly will yield, in equilibrium, a lower level of output and higher price than would result under perfect competition. The intent of regulation is to assure that the monopolist's output and price are more consistent with the results under a competitive market equilibrium. In fact, Bonbright states the following:

> Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute.
>
> This is a most intriguing proposition in view of the contention, familiar to economists, that competitive prices are optimum prices.[4]

[3] See RUCO Direct Testimony of Lon Huber ("Huber"), 9:1-11, SOLON Direct Testimony of Brian Seibel ("Seibel"), 8:9-11, SWEEP/WRA Direct Testimony of Brendon Baatz ("Baatz"), 6:18-19, and Huber Surrebuttal, 29:4-16.

[4] Bonbright, James C. (1961), *Principles of Public Utility Rates*, pp. 93-94.

Bonbright continues along these lines by asking which standard of competition should apply. Is it the economic model of "perfect competition" or some notion of mixed or "workable" competition typical of many industries?[5] Regardless of which standard of competition Bonbright is considering, it is obvious that he is addressing only the level of rates of the regulated utility that should emulate the competitive outcome.

Q. How do the parties you cited use the concept that utility regulation should serve as a substitute for a competitive market?

A. RUCO witness Huber and SWEEP/WRA witness Baatz use this concept to argue against increasing fixed charges in general and, in particular, the Company's proposed Basic Service Charge. Both Mr. Huber and Mr. Baatz cite examples of pricing structures in competitive industries with significant fixed costs but no, or negligible, fixed charges for recovering these fixed costs.

Q. What examples do Mr. Huber and Mr. Baatz cite?

A. Mr. Huber gives as an example the fact that gasoline is priced on a volumetric basis ($ per gallon) despite the fact that there are many fixed costs associated with its production.[6] Mr. Baatz cites gasoline, hotel rooms, and groceries as examples of products sold under volumetric prices although the producers of these products have significant fixed costs.[7]

Q. Do you have any thoughts on these Intervenors' use of pricing practices in competitive industries to justify opposition to certain rate elements in this case?

A. Yes. First, I believe Mr. Huber and Mr. Baatz engage in some cherry-picking in their use of pricing structures in unregulated and/or competitive markets to oppose certain utility rate elements. While Mr. Huber and Mr. Baatz use this concept to argue against

---

[5] Bonbright, p. 96.
[6] Huber Direct, 9:16-20 and Huber Surrebuttal, 29:8-12.
[7] Baatz Surrebuttal, 6:15 through 7:3.

increasing fixed charges because they don't see similar pricing in competitive markets, they have no problem advocating for other utility pricing schemes that are very rare or nonexistent in competitive markets. The most glaring example of this is their continued support for inclining block rates in the residential and small commercial customer classes. Both Mr. Huber[8] and Mr. Baatz[9] oppose the Company's proposal to reduce the number of residential class tiers from the current four to two, but I challenge them to find similar pricing schemes in competitive or unregulated markets. In fact, in competitive markets one is much more likely to find quantity discounts than quantity surcharges.

Second, the examples the Intervenors cite as similar to the production and delivery of electricity have serious flaws. The production of gasoline and food, and the provision of hotel lodging do have significant fixed costs. However, the provision of these goods is nothing like how a utility produces and delivers electricity. The most obvious difference is the availability of storage. Unlike gasoline and, to a large extent, food, electricity cannot be stored. That is what makes the market price of electricity among the most historically volatile of all commodities. A seller of gasoline does not require that refinery capacity be available to serve the instantaneous demand for the product. He or she can simply have the underground tanks filled when necessary and sell the product from storage. Likewise, the grocer does not require that food growers or suppliers have the ability to change output due to changes in demand in real time and it would be impossible to do so. However, an electric utility must have reserves ready to respond to any instantaneous changes in demand. Therefore, the utility must have sufficient fixed production capacity plus reserves, whether it be from own generation resources or power purchases, to serve the maximum instantaneous demand on the system.

[8] Huber Direct, 4:17-18 and 6:15.
[9] Baatz Direct, 4:5-11.

Another major difference between the examples cited and the provision of electricity, when combined with the storage issue, surrounds the obligation to serve. Most of us have been turned away from a hotel when seeking a room or have driven up to gasoline pumps only to find plastic bags on the handles. One's only recourse in these situations is to seek another supplier and it is likely that there will be few negative consequences for the hotel with no vacancies or the gas station that has run out of supply. However, the electric utility has the obligation to serve any customer in its service area at any time and, combined with the lack of a storage option, must have sufficient capacity plus reserves to serve the instantaneous demand of all customers. The other industries cited by the Intervenors simply do not require the level of capital investment, and therefore fixed costs, relative to the instantaneous demand for its product that is required of electric utilities. They can rely on storage, or if that is not sufficient, turn customers away.

Finally, there are many examples of firms in very capital intensive industries such as cellular and internet service providers and rental car companies that once used primarily volumetric pricing on a per minute or per mile basis with low fixed fees and have since moved to predominantly fixed charges for better cost recovery.

Q. In his Direct Testimony, Mr. Baatz takes the position that because economic theory views all costs as variable in the long run and "if we were to use the principles associated with long run marginal cost pricing to design rates, the basic service charges should be near zero."[10] Do you agree?

A. No. Mr. Baatz makes a critical error in his explanation of the role of the long run in economic theory. Just because economic theory views all costs as variable in the long run does not make them "near zero." It does mean that firms may substitute among factors of production in the long run whereas at least one factor is fixed in the short run. A firm still

---

[10] Baatz Direct, 11:16-18.

has to make the necessary capital investment to produce the necessary output to meet customer needs. Assuming the firm has customers who demand the firm's output in the future, those investments are still necessary however they are made. They don't just disappear.

Furthermore, if we take Mr. Baatz's argument to its logical conclusion then a cost justification for inclining block rates cannot be made. The justification Mr. Baatz gives in support of keeping TEP's four inclining block residential rate tiers is that eliminating any of the higher tiers will increase consumption by TEP customers and this "increased level of consumption will eventually require TEP to invest in costly infrastructure to serve growing load, thereby increasing fixed costs for all ratepayers in the TEP service territory."[11] Obviously, these increased fixed costs cited by Mr. Baatz are long run, and marginal, in nature and he makes no assertion here that they are "near zero." Inclining block rates cannot be justified from a cost perspective without recourse to long run marginal costs and Mr. Baatz contradicts himself on his earlier point.

Q. Is the utility industry currently addressing the future use of inclining block rate structures?

A. Yes. The utility industry is recognizing that inclining block rate structures have moved beyond any basis in cost. For example, on July 3, 2015, the California Public Utility Commission ("CPUC") unanimously approved a Decision on Residential Rate Reform that would move rates from four to two tiers with a 25 percent differential by January 1, 2019.[12] President of the CPUC, Michael Picker, said in a statement regarding the Decision that:

---

[11] Baatz Direct, 21:3-8.

[12] CPUC Rulemaking 12-6-013, Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates, July 3, 2015.

> The world has changed since 2001, when rates were frozen by the Legislature. Over time, with the lower tier rates being frozen, the five-tiered rate structure departed increasingly from any cost basis and imposed ever greater inequities on large-family households that were pushed into higher tiers in hot climate zones. Our decision helps align rates with the actual cost of service. It also builds a more nimble rate structure to allow us to add more and more renewables to the grid, and to encourage customers to use energy when we have excess renewables and to cut back during peak periods.[13]

IV. RESPONSE TO SOLON SURREBUTTAL.

Q. In his Surrebuttal testimony, SOLON witness Mr. Seibel states that you spent approximately thirteen pages in your Rebuttal Testimony describing how the Company "began with a representative sample of actual ratepayer data then reduced and/or modified them to a much smaller sample."[14] Please comment.

A. I am a bit confused by Mr. Seibel's statement. In the development and analyses of three-part rates for TEP's residential and Small General Service ("SGS") customers, the Company used statistically significant random samples of nearly 17,000 TEP residential customers and over 5,500 small commercial customers and at no time did the Company reduce and/or modify "actual ratepayer data into a much smaller sample." As I detailed in my Rebuttal, the Company used all of the residential and SGS sample observations to calculate and design the proposed three-part rates. The Company then grouped the sample data into typical customer profiles based on similar load characteristics to examine the three-part rate impacts. In my Rebuttal, I pointed to the fact that the

[13] CPUC Press Release, "CPUC Creates New Electricity Rate Design Structure That Reflects Actual Costs and Supports Renewables," July 3, 2015.
[14] Seibel Surrebuttal, 2:19-23.

Company calculated and presented bill comparisons under three-part rates for 45 residential and 53 SGS customer usage profiles in addition to those typically provided in a rate application.[15] The groupings that the Company used in these analyses did not result in "a much smaller sample" as Mr. Seibel states. The groupings summarize the information from the original customer samples, but the sample sizes remain unchanged. Granted, there are fewer groupings than sample observations, but the groupings do not constitute a sample, let alone a much smaller one. They represent a distillation of the information contained in the original samples. Mr. Seibel's statement implies that the Company eliminated observations from the original sample, or modified it in some way, to create a "much smaller sample," which is simply not true.

Finally, the Excel files submitted by the Company in Rebuttal[16] provide average monthly bill comparisons under the proposed residential and SGS three-part rates ***for every customer observation in the original samples.*** Also, monthly bills are calculated for every customer in the original samples so the files contain all of the information needed for any interested party to analyze monthly bill impacts for any customer in the samples.

Q. Mr. Seibel states that you did not indicate in your Rebuttal that any of his "numerical calculations presented in reference to MGS rates, LGS rates, or ratchets were incorrect."[17] Please comment.

A. I did not attempt to evaluate whether Mr. Seibel's referenced numerical calculations were correct because Mr. Seibel's entire approach to his analysis was wrong and the "numerical calculations" are therefore irrelevant. Mr. Seibel attempted to quantify the electric bill reductions for a sample of MGS and/or LGS customers due to elimination of their demand ratchets. However, Mr. Seibel failed to consider that elimination of the ratchet, all else

---

[15] Rebuttal Testimony of Richard Bachmeier ("Bachmeier"), 18:7-15 and 21:8-14.
[16] See "2015 TEP RES Dem Rate Rev_rb-FINAL.xlsx" and "2015 TEP SGS Dem Rate Rev_rb-FINAL.xlsx" submitted with Company's Rebuttal workpapers.
[17] Seibel Surrebuttal, 3:2-3.

equal, would reduce billing determinants and result in a shortfall of the revenues allocated to the relevant customer class. As a result, the rates would need to be recalculated, and most likely increased, to recover the assigned class revenues in the absence of the ratchet. I did examine Mr. Seibel's workpapers that were filed with his Direct Testimony and determined that he indeed used the same rates to compare customer bills with and without the ratchet and did not take into consideration rate changes related to reduced billing determinants. To verify whether Mr. Seibel correctly and accurately calculated the wrong thing is a fool's errand.

Q. On pages 3 through 14 of his Surrebuttal Mr. Seibel presents many TEP customer bill comparisons to support his position that TEP's SGS, MGS, and LGS rate tariffs should have no applicability restrictions and that customers should be able to choose the rate plan most economically advantageous to them. Did you review Mr. Seibel's bill comparisons?

A. Yes, I reviewed the bill comparisons presented in Mr. Seibel's testimony. However, SOLON has not yet submitted workpapers (despite being asked) and Mr. Seibel did not provide billing determinants in his testimony to check his bill calculations. I therefore cannot give an opinion on the accuracy of Mr. Seibel's bill calculations. That said, the Company could not replicate a bill impact anywhere near 92% for any elementary school in TEP's service area because of a move from the SGS rate class to LGS as presented by Mr. Seibel for Elementary School #1 on page 6 of his Surrebuttal. The Company did not attempt to evaluate any other of Mr. Seibel's calculations because without workpapers or billing determinants it is impossible to verify any of the bill impacts in his testimony.

Also, on page 3 of his Surrebuttal, Mr. Seibel indicates that SGS or MGS customers who experience 15 minutes of demand over 250 kW in the past 12 months will be moved to LGS. However, the Company changed the MGS upper limit from 250 kW to 300 kW in its Rebuttal.[18] Mr. Seibel's oversight of this change calls into question any of his calculations with respect to current SGS customers who fall into the 250 kW to 300 kW range. On pages 6 through 9 and 11 through 12 of his Surrebuttal, Mr. Seibel presents bill impacts for five schools, a health care facility, and a church purportedly showing significant impacts for those customers if they are shifted from the proposed SGS tariff to LGS. Unfortunately, without billing determinants or workpapers it is impossible to determine how any of Mr. Seibel's examples would be affected after the Company's change in the MGS upper limit.

Finally, without evaluating the accuracy of Mr. Seibel's bill impacts, I believe he makes the same error that I pointed out in my Rebuttal Testimony regarding his analysis of the Company's demand ratchets. Specifically, Mr. Seibel takes a static approach to a dynamic issue. If any customer in Mr. Seibel's examples chooses a rate plan in a rate class other than the one to which that customer was assigned in the cost allocation process, billing determinants and costs allocated among rate classes will change. In fact, if the Company were not permitted to assign tariff applicability as proposed, the cost of service study would likely need to be rerun with different billing determinants assigned to the rate classes. As a result, rates among rate classes will change. Because there are no workpapers or calculations to review, I cannot determine whether Mr. Seibel took this into account. Because he did not mention the issue in his testimony I assume that he did not.

Q. Do you have any other thoughts on Mr. Seibel's position that commercial customers should be able to choose their own rate tariff?

A. Yes. The utility cost allocation process assumes that, given customer characteristics, certain customers will take service in rate classes that correspond to those characteristics.

---

[18] Rebuttal Testimony of TEP Witness Craig Jones, 13:7-8.

If customers were allowed to migrate among rate classes without any restrictions, you would likely see low load factor customers, regardless of size, migrating to the SGS class because the MGS and LGS customers have demand charges. Because the lower load factor customers migrate to the SGS class to reduce their bills, the Company will experience a revenue recovery shortfall that would essentially be built into the system. Granted, this can be mitigated to some extent by more frequent rate cases but that does nothing for the utility's revenue loss between rate cases and it is unlikely to be an economically efficient outcome.

Mr. Seibel goes to great lengths in both his Direct and Surrebuttal testimonies to argue that the Company's proposals will have "unintended consequences" for certain customers. There is no question that customers with lower load factors will not fare as well under a demand rate structure as customers with higher load factors. There is also no question that, from a unit cost perspective, lower load factor customers cost more to serve. Furthermore, there is no question that higher load factors benefit the utility system as a whole and should be encouraged. Rates are designed to recover costs and minimize the impacts on customers with "typical" usage characteristics. While the Company is committed to assist customers who may be inordinately impacted by its proposals, rates cannot be optimally designed for every customer or every load profile. If a lower load factor customer were allowed to migrate from a rate class with similarly situated customers and a demand charge to a class without a demand charge simply to lower its bill, the incentive to improve the customer's load factor would disappear and higher load factor customers would be subsidizing the less efficient customers, an outcome Mr. Seibel seems to favor. I would be curious to see what some of TEP's higher load factor MGS and LGS customers think of Mr. Seibel's proposal.

The table on page 10 of Mr. Seibel's Surrebuttal presents a clear indication of the current subsidization within the SGS class. He states that "of the 32 ratepayers, 20 (63%) would be assigned to a rate plan that is more expensive to the ratepayer."[19] He fails to note that based on his table 37% (12 of 32) of the customers presented as migrating to the MGS tariff would see higher bills if they stayed on the proposed SGS tariff. Mr. Seibel represents the bill changes for these customers as "$0" in the table, but they are actually saving on their monthly bills by being moved to the MGS class. If one was to characterize the bill impacts more precisely based on this table, approximately 37% of customers will see a lower bill, 37% will see a nominal increase of less than 2%, and the remainder, approximately one-quarter of the group, will see a bill increase commensurate with their higher cost of service.

Finally, in his Direct Testimony, Mr. Seibel attacked the Company's proposals as "unprecedented."[20] It is hardly unprecedented to have parameters surrounding the applicability of utility rate tariffs. In fact, all investor-owned and most cooperative utilities in Arizona other than TEP have applicability requirements for commercial and industrial rate tariffs similar to those the Company is proposing. [21] TEP is currently the outlier on this issue. Mr. Seibel's reference to the Company's proposal as "unprecedented" brings to mind the words of Inigo Montoya in the movie *The Princess Bride*, "You keep using that word. I do not think it means what you think it means."

[19] Seibel Surrebuttal, 10:2-3.
[20] Seibel Direct, 27:6, 41:8, 51:8-9, 60:8-9, 70:2-3, and 78:3-4.
[21] See Exhibit RDB-RJ-1 for examples.

Q. Mr. Seibel states that, while you indicated in your Rebuttal that it only takes one counter example to refute Mr. Seibel's statement that demand ratchets disincentivize all DG, EE, and storage, he did not see any listed in your testimony.[22] Do you have a counter example?

A. Yes. In my Rebuttal, I point out that TEP's LGS and LPS (formerly LLP) rate tariffs have demand charges and at the time Rebuttal was filed, 5 of the 15 customers taking service on TEP LPS rate tariffs and 41 of the 561 customers taking service on TEP LGS rate tariffs had installed DG systems and are subscribed to the Company's Net Metering Rider R-4.[23] I should add that the Company's current LGS and LPS rate tariffs also have demand ratchets at the 75% level. Obviously, these demand ratchets did not serve as a disincentive to the installation of DG systems for the 5 TEP LPS customers and 41 TEP LGS customers who are also currently TEP NEM customers.

Q. Does this conclude your testimony?

A. Yes.

[22] Seibel Surrebuttal, 16:3-4.
[23] Bachmeier Rebuttal, 51: 7-9.

Exhibit RDB-RJ-1

aps

RATE SCHEDULE E-32 XS
EXTRA SMALL GENERAL SERVICE (0 kW - 20 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is 20 kW per month or less.

The Company initially will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company.

The Customer will be billed on Schedule E-32 S or E-32 XS depending on the Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$	0.672	per day, or
For service through Instrument-Rated Meters:	$	1.324	per day, or
For service at Primary Voltage:	$	3.415	per day

aps

RATE SCHEDULE E-32 S
SMALL GENERAL SERVICE (21 kW – 100 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 20 kW and less than or equal to 100 kW per month.

The Company will place the Customer on the Applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

The Customer will be billed on Schedule E-32 S or E-32 XS depending on the Monthly Maximum Demand for each billing cycle.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage or primary voltage when the customer owns the distribution transformer(s).

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 0.672	per day, or
For service through Instrument-Rated Meters:	$ 1.324	per day, or
For service at Primary Voltage:	$ 3.415	per day

RATE SCHEDULE E-32 M
MEDIUM GENERAL SERVICE (101 kW - 400 kW)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 100 kW and less than or equal to 400 kW per month.

The Company will place the Customer on the Applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	\$ 0.672	per day, or
For service through Instrument-Rated Meters:	\$ 1.324	per day, or
For service at Primary Voltage:	\$ 3.415	per day, or
For service at Transmission Voltage:	\$ 26.163	per day

aps

RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

AVAILABILITY

This rate schedule is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate schedule is applicable to all Standard Offer and Direct Access customers whose Average Monthly Maximum Demand is greater than 400 kW per month.

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Average Monthly Maximum Demand, as determined by the Company each year. Such placement will occur in the February billing cycle following the annual determination. The Company may also place the Customer on the Applicable Rate Schedule during the year, if the Customer has experienced a significant and permanent change in load as determined by the Company. Such placement will be based on available information.

Service must be supplied at one point of delivery and measured through one meter unless otherwise specified by an individual customer contract.

Rate selection is subject to paragraphs 3.2 through 3.5 of the Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Services.

This schedule is not applicable to breakdown, standby, supplemental, residential or resale service nor to service for which Rate Schedule E-34 is applicable.

TYPE OF SERVICE

The type of service provided under this schedule will be single or three phase, 60 Hertz, at one standard voltage as may be selected by customer subject to availability at the customer's site. Three phase service is furnished under the Company's Schedule 3 (Conditions Governing Extensions of Electric Distribution Lines and Services). Three phase service is not furnished for motors of an individual rated capacity of less than 7-1/2 HP, except for existing facilities or where total aggregate HP of all connected three phase motors exceeds 12 HP. Three phase service is required for motors of an individual rated capacity of more than 7-1/2 HP. Service under this schedule is generally provided at secondary voltage, primary voltage when the customer owns the distribution transformer(s), or transmission voltage.

RATES

The bill shall be computed at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Standard Offer Service

Basic Service Charge:

For service through Self-Contained Meters:	$ 1.068	per day, or
For service through Instrument-Rated Meters:	$ 1.627	per day, or
For service at Primary Voltage:	$ 3.419	per day, or
For service at Transmission Voltage:	$ 22.915	per day

Small General Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Not applicable to resale, breakdown, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event a Customer meets or exceeds 12,000 kWh in two consecutive months the Customer will be moved to the Medium General Service tariff.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge: $25.00 per month

Energy Charges (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
0 - 400 kWh	$0.033400	$0.053290	Varies	$0.086690
401 – 7,500 kWh	$0.043400	$0.053290	Varies	$0.096690
Over 7,500 kwh	$0.086900	$0.053290	Varies	$0.140190

Medium General Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service when all energy is supplied at one point of delivery and through one metered service.

In the event measured kW meets or exceeds 750 kW the Customer may be moved to the Large General Service rate in the next billing period.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge: $100.00 per month

Demand Charge: $14.61 per kW

Energy Charge (per kWh):

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
All kWh	$0.005000	$0.053290	Varies	$0.058290

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery, Generation Capacity and Transmission.
2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. Please see Rider-1 for current rate.
3. Total is calculated above for illustrative purposes, and excludes PPFAC, because the PPFAC changes monthly pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

ELECTRIC RATES

TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: August 1, 2009

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS1
GENERAL SERVICE LESS THAN 10 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 10 kW Rate (GS1) is applicable for single and three phase service for more than one residence from a single metering point, Commercial, Business, Professional, and various sized Industrial loads less than 10 kW. All service shall be delivered at a single service location. The Cooperative reserves the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase, or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply		Distribution Charges					Total Rate
			Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)								
Single Phase			$5.35	$1.62	$6.21	$4.82	$18.00	$18.00
Three Phase			$5.35	$1.62	$6.21	$12.82	$26.00	$26.00
Energy Charge ($/kWh)	$0.0830					$0.0505	$0.0505	$0.1335

Minimum Monthly Charge

The greater of the following, not including any wholesale power cost adjustor or any other adder approved by the Arizona Corporation Commission:

1. The Customer Charge;
2. $1.00 per kVA of required transformer capacity;
3. The amount specified in the written contract between the Cooperative and the customer.

ELECTRIC RATES

TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: August 1, 2009

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS2
GENERAL SERVICE 10 KW TO 200 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service 10 kW to 200 kW Rate (GS2) is applicable for single and three phase service for all of the electric service used for aggregated Residential loads, Industrial, Commercial, Business, Professional, and other various sized loads when the load requirement is greater than 10 kW but less than 200 kW and has a monthly load factor of 30% or less based on twelve months of actual consumption history, or in the absence of such history, on service load characteristics. All service shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single Phase		$5.35	$1.62	$6.21	$4.82	$18.00	$18.00
Three Phase		$5.35	$1.62	$6.21	$12.82	$26.00	$26.00
Billing Demand ($/kW/Month)							
First 10 kW/month					no charge	no charge	no charge
Each kW over 10 kW/month					$4.50	$4.50	$4.50
Energy Charge ($/kWh)	$0.1118				$0.0262	$0.0262	$0.1380

ELECTRIC RATES

TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
Marana, Arizona 85658
Filed By: Vincent Nitido
Title: CEO/General Manager

Effective Date: August 1, 2009

STANDARD OFFER TARIFF

GENERAL SERVICE
SCHEDULE GS3
GENERAL SERVICE LESS THAN 12,000 KW

Availability

In the Cooperative's Certificated Area where its facilities are of adequate capacity and the required phase and suitable voltage are in existence and are adjacent to the premises served.

Application

The General Service Less Than 12,000 kW Rate (GS3) is applicable for single and three phase service for all of the electric service used for aggregated Residential loads, Residential loads requesting demand billing, Industrial, Commercial, Business, Professional, and other various sized loads from 10 kW to 11,999 kW. All service shall be delivered at a single service location. The Cooperative shall have the right to meter in the most practical manner, either primary or secondary voltage.

Type of Service

The type of service available under this schedule will be determined by the Cooperative and will normally be:

120/240 volt single phase, 120/208 volt three phase or 277/480 volt three phase

Monthly Rate

STANDARD RATE	Power Supply	Distribution Charges					Total Rate
		Metering	Meter Reading	Billing	Access	Total	
Customer Charge ($/Customer/Mo)							
Single-Phase		$5.35	$1.62	$6.21	$4.82	$18.00	$18.00
Three-Phase		$5.35	$1.62	$6.21	$12.82	$26.00	$26.00
Billing Demand ($/kW/Month)	$10.70				$5.95	$5.95	$16.65
Energy Charge ($/kWh)	$0.0547				$0.02830	$0.02830	$0.0830